IN THE MATTER OF YUKON ENERGY CORPORATION 2008/2009 GENERAL RATE APPLICATION TO THE YUKON UTILITIES BOARD

FINAL ARGUMENT

YUKON ENERGY CORPORATION

May 22, 2009

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YUKON ENERGY 2008/2009 GENERAL RATE APPLICATION ("APPLICATION") TO THE YUKON UTILITIES BOARD ("YUB" OR "BOARD")

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PREFACE

OVERVIEW OF YUKON ENERGY APPLICATION

Yukon Energy ("YEC") submitted its Application to the Yukon Utilities Board ("YUB" or "Board") on October 6, 2008. The Application provides for a complete and thorough review of all aspects of Yukon Energy's operations including its costs, rates and capital spending.

YEC's Application reviews activities undertaken since the 2005 review of the utility's revenue requirement in 2005, and requests approvals that will reduce rates for most retail customers throughout Yukon, while still recovering costs necessary to supply customers in 2008 and 2009. Proposals included in the current Application are necessary to ensure that priority items identified as part of the orderly process commenced in 2005 are achieved in a timely manner for the benefit of ratepayers. In this vein, the following specific proposals are included in the Application to ensure that Yukon Energy moves forward in a manner that meets the needs of ratepayers:

- Capital expenditure levels as proposed support enhancement of system capability to displace future baseload diesel generation requirements and provide reliable bulk power supplies at a time when the existing surplus hydro generation created by past mine closures is diminishing due to ongoing and projected load growth.

- Operating and Maintenance expense levels as forecast support maintaining and improving the services for customers and the working environment for Yukon Energy employees, and provide the appropriate support for meeting governmental, regulatory and environmental requirements.

- Retail rate reductions as proposed that are focused on first block energy rates ensure that second block runoff rates do not move further away from efficient price signals and will result in rate reduction benefits being materially enhanced for the vast majority of retail customers.

- Adjustments to residential second block or runoff rates as proposed provide a modest and feasible first step towards restoring efficient price signals for residential electricity sales in Yukon. This approach will also significantly enhance rate reduction benefits for the vast majority of residential customers throughout Yukon.

SUMMARY OF APPROVALS REQUESTED

As originally set out in Exhibit B-1 (the October 6, 2008 Application) and amended in Exhibit B-10 (the April 24, 2009 Update Filing), and summarized in Attachment A to Exhibit B-12 (the Yukon Energy Opening Statement), Yukon Energy's Application seeks Orders of the Board on the following matters:

1. **2008 and 2009 Revenue Requirement:** Approval of the forecast revenue requirement of $29.085 million for 2008 and $31.462 million for 2009, and including approval as required of the following costs, revenues and other related provisions:
    a. **Fuel and Purchased Power Costs** of $0.487 million and $0.582 million in 2008 and 2009 respectively, including approval to adjust diesel prices used in setting fuel costs to reflect the forecasts in the Application.
    b. **Non-Fuel Operating and Maintenance Costs** of $12.362 million and $13.228 million in 2008 and 2009 respectively.[1]
    c. **Depreciation and Amortization Expenses** of $6.391 million for 2008 and $6.930 million for 2009 including approval to amortize regulatory costs,[2] including an updated estimated $1.1 million of hearing costs related to the current GRA to be amortized $400,000 per year over the test years with the balance currently estimated at $300,000 to be amortized in 2010.[3]
    d. **Mid-Year 2008 and 2009 Forecast Rate Base costs** of $144.419 million and $150.758 million for 2008 and 2009 respectively, including costs for capital works projects brought into service (or forecast to be brought into service) since the 2005 Required Revenues and Related Matters application as well as deferred costs and working capital forecast to be included in rate base.
    e. **Return on Rate Base** of $9.845 million in 2008 and $10.724 million in 2009, including an allowed rate of return on equity ("ROE") of 8.64% for 2008, and a 2009 ROE of 8.49%.

[1] This includes approval to increase the annual appropriation to the Reserve for Injuries and Damages to $150,000 from the current $50,000 level starting in 2009, and approval to apply 0.463 million of the Faro Dewatering Account balance against the Reserve for Injuries and Damages as referenced in item #4.

[2] $0.643 million related to the regulatory review of Yukon Energy's 2006-2025 Resource Plan; $0.243 million related to the regulatory review of the Minto Explorations Power Purchase Agreement, and $0.185 million related to the regulatory review of the Carmacks-Stewart Transmission Project ("CSTP") under Part 3 of the Public Utilities Act. The amortization of these costs are discussed in the Application at pages 3-17 and 3-18.

[3] At the time of filing, YEC noted that the "intensity and duration of the regulatory process" could not at that time be determined, and sought approval to adjust the then noted amount of $800,000 to reflect the full actual amounts incurred or ordered to be reimbursed at the time of the final refiling in the current GRA process, following receipt of all final Orders from the Board.

2. **2009 Rates:** Approval of rate adjustments, by class for all related customers of Yukon Energy and YECL:
   a. **Retail Rates:** rate adjustments for all YEC and YECL retail customers consisting of:
      i. A new Rider U "Yukon Energy Rate Reduction Rider" for each retail class that is applied to all first block rates (and lighting rates) with variations as required by rate class to prevent any rebalancing of overall rate revenues as between customer classes[4];
      ii. Residential class base rate adjustments as proposed in the Application to promote economy and efficiency within this class;[5] and
      iii. Adjustments to include Pelly Crossing in the Hydro rate zone rate schedules and to remove this community from the Small Diesel rate zone rate schedules.
   b. **Wholesale Rates (Rate Schedule 42):** Approval for the following adjustments:
      i. concurrent with residential rate class runout rate adjustments, to increase the Wholesale Rate (Rate Schedule 42) charged to YECL throughout Yukon by 0.011 cents/kW.h[6], to maintain revenue neutrality to YECL with respect to base rate revisions; and
      ii. to adjust, starting in 2009, the rate established for the Energy Reconciliation Adjustment (ERA) provisions of Rate Schedule 42 to 37.37 cents/kW.h using the same principles established in the 1996/1997 GRA to reflect the current forecast incremental cost of diesel generation in WAF.
   c. **Major Industrial Rates (Rate Schedule 39) and related Rider F:** Approval to implement Rate Schedule 39 as mandated by OIC 2007/94 (and approved by Board Order 2008-13), to give effect to the Rider F provisions on a basis consistent with this GRA, and as described in Exhibit B-10, by way of a fixed Rider F of 0.109 c/kW.h and additional variable Rider F as established from time to time.

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[4] Rider U at the following for first block energy (except as otherwise noted): -0.496 cents/kWh for residential non-government rate schedules; -0.715 cents/kW.h for residential government rate schedules; -1.50 cents/kW.h for general service non-government and municipal rate schedules; -3.96 cents/kW.h for general service Federal and Territorial Government rate schedules; -3.48% for Lighting rate schedules, applied to all base rates.

[5] For residential non-government rate schedules: a base rate decrease of 1.36 cents/kW.h for the first 1000 kW.h in any one billing month ("residential first block"), and an offsetting base rate increase of 5.61 cents/kW.h for all energy over 1000 kW.h in any one billing month ("residential runoff block"). For residential government rate schedules: a base rate decrease of 1.66 cents/kW.h for residential first block energy, and an offsetting base rate increase of 5.61 cents/kW.h for residential runoff block energy.

[6] Increase from 6.840 cents/kW.h to 6.851 cents/kW.h.

3. **Secondary Energy Rates (Rate Schedule 32):** Approval to adjust the terms of Rate Schedule 32 interruptions.[7] Also approval to establish Yukon Energy secondary energy revenue amounts for the GRA Application at the new baselines set out in the Application.[8]

4. **Faro Dewatering Account:** Approval as follows:
   a. To apply $0.463 million of the Faro Dewatering Account balance against the Reserve for Injuries and Damages;
   b. To apply $0.087 million of the Faro Dewatering Account balance, as set out in Exhibit B-10, to address offset net revenue losses due to delay in the final connection timing of Minto mine and Pelly crossing loads to the CSTP; and
   c. To apply against the Faro Dewatering Account balance secondary sales revenue losses, if any, arising due to below-average water flows in any year after 2008.

OVERVIEW OF YUKON ENERGY FINAL ARGUMENT

The total documentation and evidence in this hearing are substantial. There are in excess of 842 information requests (not including refiling of several revised interrogatory responses on April 1, April 14 (response to Board Order 2009-4) and April 24 (as part of 2008 Update Filing), 29 undertakings and approximately 600 pages of transcript. To date, there have been over 60 exhibits, and 6 Board Orders flowing from the Application.

Yukon Energy submits that all evidence necessary for the Board address with the Orders requested is in the record. While there were 7 registered intervenors, only 5 actively participated. No intervenors, however, provided evidence in the proceeding.

Yukon Energy's Final Argument provides the support from the record for the requested Orders, focuses on the extensive evidence examined within the scope of the Board's review of the Application, and includes the following major sections:

- Introduction - Context for Yukon Energy's Application;
- System Sales and Generation;
- Yukon Energy's 2008/2009 Revenue Requirement;

[7] Such that future diesel requirements are to be reviewed based on five day weather and load forecasts rather than the current seven day forecasts.

[8] 6.5 cents/kW.h for the retail rate for all sales starting January 1, 2008, 7.2 cents/kW.h for sales starting April 1, 2008, 8.3 cents/kW.h for sales starting July 1, 2008 and 9.3 cents/kW.h for sales starting October 1, 2008 and thereafter at 9.3 cents per kW.h through all of 2009, consistent with approved rates charged in each period (corresponding wholesale secondary rates equal 1.1 cents/kW.h less than these amounts pursuant to Rate Schedule 43). No changes are proposed in the rates to be paid by secondary customers or the approach to setting those rates on a quarterly basis.

- Rates;
- Capital Projects; and
- Board Directives and Recommendations.

To the extent that the Board and intervenors examined specific issues with respect to specific parts of Yukon Energy's Application through interrogatories or cross-examination, Yukon Energy has attempted in this argument to address the apparent concerns raised. However, in the view of Yukon Energy, its filing, the answers to the many interrogatories, and other evidence submitted (including undertakings) fully address all such concerns, and fully support the reasonableness and necessity of the proposed revenue requirement. Further, no evidence-based contrary position has been tendered by any party.

1.0 INTRODUCTION - CONTEXT FOR YUKON ENERGY'S APPLICATION

1.1 TIMING OF APPLICATION AND ORDERLY PROCESS

1.1.1 Orderly Process Established in 2005

In 2005, Yukon Energy sought to initiate an "orderly process" to deal with key regulatory issues facing both utilities (YEC and YECL). In that application retail rate changes were deferred until a subsequent hearing where both YEC and YECL had been before the Board for approval of revenue requirements for the same test period. It was noted at that time that in the future there would be a need to deal with the following priority items:

- Retail rate matters and the need to restore efficient price signals for second block rates;
- Board direction relating to rate shift programs to target 90 to 110% RCC ratios for all retail customer classes;
- Future industrial customer rates and wholesale rate setting;
- Developing a consistent and simple approach to setting ROEs for both utilities; and
- Resource Plans, including capacity planning criteria and future major capital bulk power supply options.

1.1.2 Regulatory Issues Dealt with Since 2005

YEC, over the course of 2005 through 2007/08, successfully started to address many of these items:

- The 2005 Required Revenues and Related Matters Application updated YEC's revenue requirement and operations, and Order 2005-12 set out an approach to address YEC revenues requirements for 2005 to 2007, with 2008 needing a new revenue requirement.
- The 20-Year Resource Plan provided the opportunity for a major YUB review (including a report and recommendations to the Minister) of the following issues:
  - New capacity criteria and near term capacity required.
  - Review of first "regulated project" from the Resource Plan (CSTP) pursuant to part 3 of the PUA.
  - Other major near term projects were reviewed and are underway or in active planning.
- Industrial rates were reviewed as part of the Minto PPA hearing (2007) and subsequent direction from government (OIC 2007/94) through 2012.

Further, YECL 2008-2009 GRA has resumed YUB regulation of YECL revenues.

1.1.3 Next Phase in the Orderly Process Started in 2005

YEC has with its current Application set the stage for the next phase of an orderly process focused on planning to address new energy-focused issues including the following priority matters:

- Need to plan for new renewable energy supplies to offset expected future diesel fuel requirements.
- Need to begin to address required changes to rate design to provide for more meaningful efficiency signals, including updating price signals for runout rates for retail and wholesale customers.

1.1.4 Cost of Service Study will be Undertaken by YEC/YECL

Order 2009-1 and subsequent Board correspondence (Exhibit A-10) has provided specific direction that despite the restrictions on rate rebalancing that will persist until 2013, the Board still wishes YEC and YECL to proceed with a Cost of Service Study. In this vein, YEC has corresponded with YECL (Exhibit B-11) and intends to move forward with discussions and consultations related to a joint cost of service filing, rate design matters not addressed in the Application, Electric Service Regulations and other matters as outlined in Exhibit B-11.

1.2 BULK POWER SYSTEM RESOURCE PLANNING AND DEVELOPMENT CHALLENGES AND IMPACT ON CAPITAL PROJECTS

Yukon Energy is the main generator and transmitter of electrical energy in Yukon, accounting for over 90% of annual Yukon power generation, all of it on the two existing grids. The Application, interrogatories and hearing testimony have outlined major bulk power resource planning and development challenges facing Yukon Energy today, and how these challenges are impacting capital spending requirements and priority rate adjustments.

Yukon Energy 20-Year Resource Plan and Near-Term Projects Committed to Date

Yukon Energy has confirmed that the need and justification for several major near term bulk power system capital projects included in YEC's proposed rate base were reviewed and recommended by the Board in the 2006 hearing to review YEC's 20 Year Resource Plan as well as the Part 3 hearing on the Carmacks-Stewart Transmission Project. Aside from connecting the grid and surplus hydro generation to new industrial and diesel-served community loads, these projects provided diesel generation capacity to address winter peak capacity planning shortages.

Yukon Energy responded to questions on the purpose of the Resource Plan and the rationale for this new diesel capacity.[9]

Emerging Near Term Requirement for Renewable Energy Projects

As stated by Mr. Morrison (transcript page 34), "Existing hydro generation surpluses will likely now be largely utilized within the next few years, resulting in the need to develop new renewable supply sources so that high-cost base-load diesel generation and the related greenhouse gas emissions can be minimized on both the Whitehorse-Aishihik-Faro (WAF) and Mayo Dawson (MD) grids."

Yukon Energy has demonstrated that planning and study costs (as deferred costs) included in the Application for major renewable resource projects are needed to prudently plan to meet potential new system load requirements and displace near term baseload diesel requirements. These costs are forecast to be work in progress during the test years, and thus do not affect forecast 2008 and 2009 revenue requirements.

Yukon Energy responded to IRs, cross exam and undertakings to clarify and confirm the need to plan today for near term renewable energy projects to displace emerging baseload diesel generation.

Undertaking #28 provides a table with a summary by grid of YEC's projected generation requirements and related forecast baseload diesel requirements for the years 2010 to 2015, assuming long term average generation from existing facilities and the Aishihik 3rd turbine. Absent Carmacks Copper mine loads, projected long term average baseload diesel generation requirements for the WAF and MD approximate 15 GWh/year by 2011 and 29 GWh/year by 2012. In the event that the current Aishihik Fish Act Authorizations restrictions remain in place, the undertaking notes that these diesel generation requirements would be further increased by up to 10 GW.h/yr.

Undertaking #28 also confirms that with Carmacks Copper added in 2012, projected overall long-term average baseload diesel generation increases to 64 GWh/year increasing to over 75 GWh/year by 2015 (again, these would be further increased by up to 10 GW.h/yr so long as the current Aishihik Fish Act Authorizations restrictions remain in place). Pages 2-3 Undertaking #28 (and discussion at transcript pages 602-24) note that in considering the current forecast, the combined four priority near term hydro projects currently in the planning and feasibility study stage (Mayo B, Gladstone Diversion, Atlin winter small scale storage and Marsh Lake fall-winter storage) would all be required with the advent of Carmacks Copper mine.[10]

[9] See transcript with responses to Mr. Keough at pages 75-94. See also sections 2.4, 5.2.1.2, 5.2.1.3 and 5.2.1.4 of the Application; the response to CW-YEC-1-31 (new diesel capacity); the response to YUB-YEC-1-36(a) CSTP Stage1 benefits, which provides the basis for current requested rate reduction.

[10] Transcript page 602-24: "Mayo B project, Carmacks-Stewart project if the funding is available are needed in the time period of what we're trying to deal with, 2011, fall of 2011, early 2012 without Carmacks Copper being committed, they will both be of value -- they will be of value to a system looking at the values emerging to 2012 with the Faro reclamation

Resource Planning Addresses Bulk Power System Risks

Yukon Energy has demonstrated that its bulk power system planning addresses risks and requirements to protect ratepayer interests.

Mr. Keough asked at transcript page 87 whether YEC's pursuit of numerous major generating projects led to overly optimistic or aggressive growth forecasts. It was noted by Mr. Osler that the pursuit of major generating projects does not lead to developing overly optimistic growth forecasts, but quite the opposite, leads to more careful assessment of the forecast in order to reduce the risks that the utility may be exposed to:

> YEC is trying to do innovative things and taking the risks for it, it wants to know it's got the best forecast available, thank you very much, as well as the best everything else it can available if it's going to put its neck out and try to make things happen.

Further at page 88, line 9 to page 89, line 1, it was noted:

> There is nothing in it for YEC to make a forecast that would drive it to be promoting projects that then fail. So if anything, the more risk you are going to take to try and develop things to keep us off diesel, the more you really want to know that your forecasts are realistic.
>
> The safest thing to do, looking at history, is just to not do what YEC is trying to do, just let the growth happen with diesel and let the customers pay the charges through the Rider F and everything else.

But what YEC was concerned about is the implication of taking that strategy and trying to understand what different has to be done to avoid that type of outcome.

In response to questions addressing the short-term life of mines, it was noted at page 102 that in planning the system to meet larger, lumpier mine loads, YEC also considers load growth of the

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and things like that. With Carmacks Copper if it comes on the system in that type of time period or the next year it adds 40 gigawatt hours. So you can figure out from there why they say we need Gladstone, we need these other projects available. It's a very major leap if you add Carmacks Copper to the picture. And that is something we are told we have to plan for. Beyond that, the load is growing at about, you know, 6, 7 gigawatt hours a year on the main system. So it ended up with us saying without any development at all before 2015, without any new resources being put in place at all on the Aishihik third turbine, we seem to need 50 to 100 gigawatt hours of load. So it's not so much the triggering of one project of the other project. You might say they are very valuable core projects, and where do we get the rest, because people are worried that if we develop problems in the project we still end up with a fair amount of diesel. And that's why they are looking at geothermal, and that's why they are looking at other longer term projects to be able by -- as soon as possible be ready for those types of things. But we're just looking at Alexco and Carmacks Copper as big triggers, and Alexco is already on the way to commitment. Carmacks Copper is such a big lump that it -- if it comes along, I don't think we can meet it in renewable resources at least in the initial years. We will be running diesels."

rest of the system in order to understand the extent to which load growth is occurring independent of a particular mine that may be coming onto the system or going off the system. Mr. Bowman noted at page 102 "it is important to emphasize there is a big difference between the type of mining loads people are talking about these days, Minto at 30 gigawatt hours and or Western Copper at 40 or 50 gigawatt hours, in relation to the fact that the ongoing system is growing at 5 to 8 to 10 gigawatt hours a year on its own.[11]" Even if the mine only operates for a short period (5 to 8 years), by the time the mine closes the generation required to serve the mine's load will be required to supply other firm retail load on the system.

Discussion in cross examination at page 84-85 note the following additional key points with regard to current load forecasts and required planning activities to manage risks and development for new renewable sources of generation:

- "In some circumstances, the planning activities, in order to be able to meet a potential future need, have to take place long in advance" (page 84, lines 1-4).
- "All loads have some degree of risk and uncertainty to do with them. Some of the bigger ones have a lot more risk, and we dealt with that through the purchase power application, through the Carmacks-Stewart application, all of which flowed from the resource plan. We were dealing with material risk of a load and our ability to serve it on a timely basis".
- "I think what the resource plan is showing is that if you do not want to be stuck with meeting major new needs by just running some more diesel, we are going to have to grapple with the planning problem of what do we do when and how do we protect ourselves against going too far before we have some more knowledge or certainty, but also if we don't do enough in the planning at various stages, we won't have any opportunity. We can [cannot] know for certain to have a project in place when it is needed to displace diesel. So the resource plan, Mr. Keough and Madam Chair, is dealing with that problem. And it is for Yukon and the size of this system and the challenges of major new industrial loads, Chapter 5 of the Resource Plan document was trying to deal with the balancing of the uncertainties about these major new load and the problems of trying to find the right match of new supply options. Yukon has some very specific challenges in that regard, we thought, over the next 20 years" (Transcript page 86-87).

[11] Mr. Bowman noted this was quite different from Faro mine which required 180 GWh a year leaving a large surplus when it closed.

2.0 SYSTEM SALES AND GENERATION

2.1 SALES FORECAST AND FORECASTING METHODOLOGY

Yukon Energy's sales and revenue forecast is provided in Tab 2 of the Application. Consistent with normal regulatory practice, this forecast was not updated as part of Exhibit B-10.[12] No party filed evidence indicating that any component of Yukon Energy's sales forecast or forecasting methodology was unreasonable. However, extensive additional evidence was provided by Yukon Energy before and during the hearing in response to information requests and cross examination related to YEC's forecasting methodology. Individual matters related to YEC's forecasting methods that were the subject of detailed interrogatories or cross-examination are addressed separately below.

YEC fully described its forecasting methods in CW-YEC-1-2(a) Revised, LE-YEC-1-7(a); YECL-YEC-1-21 and in YECL-YEC-1-19 Revised (wholesale forecast), YECL-YEC-1-23 (secondary sales), and YECL-YEC-1-20 (industrial sales). YEC's forecasting methodology was also discussed on the transcript at pages 223-24 and 238 to 252.

Generally, YEC has taken a reasonable and efficient approach to forecasting retail, industrial and wholesale sales based on its role as primary generator and transmitter in Yukon, given that it has one major wholesale customer, one major industrial customer and a relatively small percentage of Yukon's retail customers. The methods used are efficient, reasonable and consistent with the approach suggested by the Board in Order 2009-2.

2.1.1 Wholesale Sales to YECL

Yukon Energy's 2008 and 2009 wholesale forecasts are reasonable and should be adopted. Questions raised regarding methodology and other matters have confirmed the reasonableness of the approach adopted by Yukon Energy in the circumstance applicable to the Application.

Intervenors in interrogatories and in cross-examination questioned YEC on the methodology used to forecast wholesale sales to YECL noting the following issues and concerns (all of which concerns were addressed by YEC in interrogatory responses and in cross-examination):

- YEC's 2008 wholesale sales forecast was 1,293 MWh lower than YECL's initial wholesale forecast; this variance is increased due to the revised forecast included in

[12] As noted in the update filing and in discussion at page 243, the April 24, 2009 filing was intended only to update the application for 4 items identified as major outstanding items that would be materially affected by receiving further intervening information after the application was filed in October 6, 2008 including the outcomes of YECL's GRA, the connection date of stage 1 CSTP, the ROE for 2009 adopted by the BCUC and updated rate case costs. The application was also updated to correct a fifth item which was an error in the application related to WIP in 2009.

YECL's compliance filing (see YECL-YEC-1-19(c) and CW-YEC-1-3(b)). This was also discussed on the transcript at page 248-50.

- The initial variance was largely due to the fact that YEC relied upon 6 months of actuals in developing its forecast which indicated below forecast loads in the early months of 2008. Mr. Bowman noted on the transcript that with regard to the wholesale forecast, the 2008 number "is effectively YEC's annual business plan number, which was developed working with YECL. The only thing Yukon Energy did differently was some difference in the monthly distributions and updating the -- and for actuals and leading up to the time we filed.[13]
- It was noted at page 241-42 that while the preliminary actual sale forecast for 2008 was higher than forecast in the GRA Application, other forecast items such as O&M came in lower or higher than forecast as well, and that it was not appropriate in these circumstances to pick and choose which forecast items to update.

- Questions were asked about the basis for growth rate applied to YECL's purchased power forecast and YEC's knowledge of the underlying load growth drivers in the wholesale forecast;
  - The 2009 forecast was effectively based on YECL's purchased power forecast for 2009 inflated to reflect the average growth rate based on the information then available to YEC.
  - At page 240 it was noted that with regard to the forecast for 2009, the 267.7 MWh forecast included in Schedule 3.1 of YECL's compliance filing (per Board Order 2009-2), was considerably higher than YECL's initial forecast for 2009 included in its GRA filing, but within approximately 0.3% of YEC's forecast (267.0 MWh as filed in October 2008), confirming the reasonableness of YEC's 2009 wholesale forecast.[14]
  - The basis for the growth rate applied by YEC to YECL's purchase power forecast is discussed in CW-YEC-1-3(d)[15] and YECL-YEC-1-19(d).[16]

[13] At page 250 it is noted by Mr. Bowman regarding the difference in the 2008 forecast between YEC and YECL "They may have used a slightly different monthly distribution, but the same annual sales forecast. he differences in 2008 arise for effectively two reasons as noted, that the primary one being we had a half year of actuals."

[14] YECL originally applied for a primary purchased power forecast of 263,202 MWh for 2009. Based on a combination of directives from the Board (to increase sales forecast and also Fish Lake generation), YECL's refiling has 2009 primary purchased power forecast of 267,747 MW.h (increase of 1.7%). YEC's GRA has 2009 Wholesale (firm) sales of 266,926 MW.h – this is basically identical to what YECL's revised refiling has (0.3% lower than YECL's compliance filing).

[15] CW-YEC-1-3(d) describes YEC's wholesale monthly load forecast for 2009 and notes that for all loads other than Pelly Crossing, YEC applied a load growth of 2.5% above the same month in 2008 (actual or forecast). In the same response it is noted that the 2.39% figure "arises as in the final GRA preparation, Pelly Crossing load was allocated 2.3 GWh of the total wholesale load, rather than the original estimate of 2.0 GWh, which served to reduce the load growth otherwise attributed to "ongoing" sales by about 0.1%".

[16] YECL-YEC-1-19(d) provides the justification for the 2.5% value calculated for the current GRA noting that the 2.2% average growth rate for 2001 to 2004 was provided in the 20 Year Resource Plan hearing; the 2.5% value used in the current GRA was calculated when YEC did not have YECL Fish Lake generation readily available and thus was calculated off of simple WAF wholesale sales (i.e., YECL WAF native load net of Fish Lake generation.) With Fish Lake generation included, the YECL native load growth over the period 2004 to 2007 is 2.9% per year, and over the period 2004 to 2008 is 2.8%.

  - The rationale underlying why this type of growth rate was applied and how it has been applied in previous proceedings since the 2005 Required Revenues and Related Matters hearing was discussed in YECL-YEC-1-19(d) and in discussion on the transcript at page 246. YECL-YEC-1-19(d) provides the following basis for YEC's use of the historic growth rate as opposed to detailed statistical analysis relied upon by YECL:
    - The response notes that "YEC has reviewed longer term wholesale sales growth trends since 1987 and concluded that since the 5 year hiatus on growth in Yukon after the closure of Faro mine, the loads have been steadily climbing at a rate that more readily approximates the levels shown in YEC's GRA".
    - The response also notes that "YEC believes that such growth reflects overall Yukon growth related to a combination of population, government service sector and business sector activities sustaining Yukon development after a recovery period following the closure of the Faro mine and disputes YECL's view that current growth trends reflect on-off general service load increments in Whitehorse".
- Both YECL and CW raised questions about whether YEC weather normalizes its forecasts (in YECL-YEC-1-19(i) and (j) and CW-YEC-1-2(a); this was also discussed in cross examination (pages 223-24)):
  - YEC has noted in response to these IRs that it does not weather normalize its sales due to the small size of its own retail customer classes served and due to the seasonal nature of many of the retail customer loads in each class.
  - Further, as noted on the transcript at page 224, to the extent YECL weather normalizes the forecasts supplied to YEC such forecasts are weather normalized; YEC does not use weather normalization or any regression analyses in its load forecast in part due to the fact that it does not have access to the necessary data and in part due to the view that access to such data and analysis would not materially improve upon YEC's existing forecasting methods.
  - YECL-YEC-1-19(d) notes that "YEC does not believe that overall wholesale forecasting at least for the current Application, would necessarily be improved through prior access to such additional information."

It was also noted by YEC's witnesses that based on actual results, year to year access to voluminous amounts of additional customers data for wholesale (or other) forecasting purposes may not always lead to the most accurate or most efficient result. The following is noted regarding the basis for the forecasting approach used by YEC and why this approach is reasonable and appropriate in the circumstances:

- Yukon Energy primarily provides wholesale service to YECL and does not have access to YECL's detailed customer information and therefore cannot undertake the same type of detailed statistical analysis performed by YECL.

- Mr. Bowman noted both utilities "pouring over" customer-specific data may not lead to the best results and there is a certain efficiency in having the utility primarily responsible for distribution take on the role of accumulating and analyzing the detailed customer specific data. YEC did not want to replicate the work performed by YECL, and given the limited customer specific data available to YEC for YECL's customers could not usefully replicate such analysis for wholesale customers. There is value in YEC performing a reasonableness top-down correction on the data provided by YECL. It was noted that this was a "common type of cross-checking one would do on a set of data". (See discussion at transcript pages 247-48)
- YEC's forecast methods are easy to understand and interpret. YEC relied on average annual growth rates based on data that was available to YEC (summarized in YECL-YEC-1-19 (d)). YEC's simplified forecast methods are also consistent with comments made in Board Order 2009-2 regarding the detailed and data-intensive statistical forecasting methods used by YECL. In that Order the Board acknowledges "YECL performed a great deal of detailed analyses to arrive at its sales revenue forecasts as outlined in the Application", but notes that it "is not convinced that a more simplified approach could not achieve reasonable results with far less effort and cost to ratepayers.[17]"

2.1.2 Major Industrial Sales Forecast

Forecast industrial sales provided by Minto for the last three months of 2008 were 6,845 MWh and forecast industrial sales for 2009 were 29,023 MWh (slightly lower than the 32.5 GWh per year load assumed in the PPA Application, but still slightly above the minimum take or pay amounts as set out in the PPA. No other mines are forecast to require service under Rate Schedule 39 in the test years). The basis or reasonableness of these forecasts was not challenged during the hearing.

During the hearing, the variance in YEC's industrial sales to Minto was noted in cross examination by YECL;[18] it was noted that actual consumption was 53% less than forecast in 2008. YEC confirmed in response to these inquiries that the difference between actual and forecast for 2008 related largely to the fact that Minto did not connect to the grid on October 1, 2008 as assumed in the Application, as filed, and commencement of delivery to the mine did not occur until November 22, 2008. Therefore Minto was connected for less than half the time period in 2008 that the mine was assumed to be connected in the Application. The Application provided for adjustment of the 2008 Industrial forecast to reflect the actual date of connection for the mine.

Yukon Energy's connection of this Industrial customer before the end of 2008 was a major achievement under all of the circumstances related to CSTP Stage One, and provides the basis for the rate reduction proposed for 2009. The Application's proposed adjustment to the 2008

[17] Appendix to Order 2009-2 at page 6.

[18] At transcript age 105-06 Mr. Keough references UCG-YEC-1-21 Revised which indicates for 2008 that actual consumption at Minto Mine in 2008 was 53% less than forecast.

forecast and costs to reflect the actual date of connection is a fair and reasonable method of addressing the uncertainties related to the connection timing for this load.

2.1.3 Firm Retail Sales Forecast

Reasonableness of 2008 and 2009 Forecast

Yukon Energy's firm retail sales forecast, which is discussed at page 2-7 to 2-8 of the Application and set out in Tables 2.2 through 2.4, is reasonable. In the context of the small size of YEC's retail customer loads relative to total firm sales, YEC's retail sales forecast methods consistently provide a reasonable level of accuracy while maintaining efficiency and simplicity consistent with the approach recommended by the Board in Order 2009-2.

As noted above, there is no evidence on the record of this proceeding that YEC's forecast accuracy would improve as a result of adopting more detailed statistical methods. CW-YEC-1-4 (a) provides a comparison of forecast and actuals for 2005 (approved) through 2007. CW-YEC-1-4 (b) requested an explanation for variances greater than 5% between forecast and actual in 2006 and 2007 and (c) requested an explanation for variances greater than 5% between forecast and actual for 2008. Over 2006 and 2007 the only material variance between forecast and actual (i.e., greater than 5%) in the retail forecast noted was streetlights in 2006.[19] It was noted that based on preliminary actual, there was no variances between forecast and actual sales for 2008 greater than 5% in total retail sales.

The forecasting methodology for retail sales was fully described in detail in response to LE-YEC-1-7(a) as well as in revised response to CW-YEC-1-2(a) where CW requested a full explanation and demonstration of the statistical forecasting methods used by YEC to forecast energy sales and/or MWh sales per customer in tables 2.3 and 2.4.

In response to CW-YEC-1-2(a) Revised[20] YEC fully described its approach (compared to detailed statistical methods that were used by YECL) and detailed the reasons why it did not use (and therefore could not provide for review by intervenors) detailed data or the demonstration of statistical methods similar to that provided by YECL during its GRA process.[21] As noted above, this simplified approach adopted by YEC is appropriate given that YEC is a utility primarily focused on generation and transmission, and it directly serves few retail customers relative to its total firm sales.

[19] Per CW-YEC-1-4 (b) due to Dawson and Mayo adding street lights not anticipated at the time the business plan forecast was filed.

[20] CW contrasted the type of "very in depth" statistical data and information provided by YECL during its GRA which "clearly demonstrated its forecasting methods," and requested that similar data by provided by YEC.

[21] It was noted that YEC uses customer data for the prior 3 years to determine the monthly average use per customer, and this is multiplied by the forecast number of customers to derive forecast sales by month by rate class. Specific adjustments for each retail customer class are discussed further in that response. This simplified approach to forecasting retail sales is considered appropriate given the small size of YEC's retail customer loads relative to its total firm sales.

2.1.4 Secondary Sales Forecast and Surplus Hydro

Rate Schedule 32 includes provisions to interrupt secondary sales as required to ensure they are served only by surplus hydro and are not served by high cost diesel. Secondary sales are only available when, and to the extent that, surplus hydro energy is forecast to be available. As noted in the Application (page 2-9 to 2-10) interruptions to secondary sales may also occur due to peaking diesel operation or due to water availability.

The Application notes that the availability of surplus hydro power is expected to decrease (particularly during winter and shoulder seasons applicable to secondary sales heating loads) with increased firm loads (including new industrial loads). The forecasts in the Application consider all relevant factors, are reasonable, and were not challenged by any party in the hearing.

Page 2-3 of the Application notes that the preliminary 2008 and 2009 load forecasts for secondary sales developed by Yukon Energy (in consultation with YECL), did not fully consider issues related to secondary sales availability following connection of the Minto Mine. Yukon Energy had initially adopted a conservative set of assumptions that no secondary sales were to be included in Yukon Energy's initial 2009 load forecast outside of a very limited amount of sales in summer months from excess flows at Whitehorse.[22] After further consideration (and as noted in the Application at page 2-9 to 2-10) this was subsequently revised upwards to 20,557 in 2008 and 16,613 in 2009.

Preliminary actuals for 2008 as set out in Exhibit B-10 provide 18,753 MWh of sales in 2008. CW-YEC-1-4(d) and UCG-YEC-1-28 provides that these lower than forecast sales were due to equipment breakdowns at a major secondary sales customer and material interruptions in the latter part of the year (due to cold weather and outage caused by loss of WH3).

In relation to YEC's secondary sales forecast YECL-YEC-1-23(a) also discusses why YEC does not prepare its secondary sales forecast based on analytical "normalized" temperatures.

[22] This formed the basis for forecast included in YECL's 2008/2009 GRA which reflected only 16,853 MWh of retail secondary sales in 2008 and 6,954 MWh of secondary sales in 2009 – 3,052 MWH and 9,029 MWh below Yukon Energy's GRA forecasts for secondary sales in 2008 and 2009.

3.0 YUKON ENERGY'S 2008/2009 REVENUE REQUIREMENT

Yukon Energy's Operating and Maintenance (O&M) costs are outlined at Tab 3 of the Application (pages 3-4 to 3-15). Total O&M costs include: labour; fuel; purchased power; production; transmission; distribution; general operations and maintenance; customer accounting and marketing; administration; insurance and provisions to the reserve for injuries/damages; and property taxes.

3.1 OVERVIEW OF COST PRESSURES EXPERIENCED SINCE 2005

YEC has experienced increasing cost pressures since 2005 primarily relating to costs arising from increased operation costs generally and feasibility and planning costs necessary to bring on the next generation of bulk power infrastructure. Identified cost pressures included the following[23]:

- Higher fuel costs; diesel fuel cost increases reflect the biggest percentage growth from 2005 to 2009; approximately $0.302 million of the forecast revenue requirement change from 2005 to 2008, and $0.397 million of the change from 2005 to 2009, is due to fuel and purchased power costs for generation, including incorporating recent fuel price increases in forecast costs of diesel fuel consumed.
- Increased labour costs and employee requirements, most of which had already occurred by 2007, per page 3-6;
- Other non-fuel O&M cost increases in the range of experienced inflation over the period;
- Amortization cost increases related to deferred costs (including planning studies, regulatory activities and licensing costs, and hearing costs); and
- Increased average costs of debt (as a component of return on rate base).

Completion of CSTP Stage One has contributed to increases in revenue requirements in the test period; however, it is also the key factor leading to an overall 2009 rate reduction due to

[23] The amounts set out in this section reflect 2005-2007 actuals and 2008-2009 test year forecasts, as applied for by Yukon Energy. As noted in Exhibit B-10 (Appendix B), Yukon Energy's preliminary actual 2008 cost levels were materially higher than forecast in the GRA for 2008, and consequently Yukon Energy will record an actual ROE for 2008 that is well below the levels sought in this application. The 2008 preliminary actuals indicate significant one-time labour costs, as well as a now known recurring pension cost adjustment that will affect 2009 (totaling $0.135 million for 2009) which Yukon Energy has not sought to amend its application to include in 2009 forecasts. With respect to non-labour, the cost pressures experienced in 2008 are set out as reflecting, in large part, the inherent difficulties that arise in dealing with aging infrastructure.

additional revenues and cost savings derived from commencement of grid service to Minto mine and Pelly Crossing, which far exceed the increases in revenue requirement.

3.1.1 Fuel and Purchased Power

Yukon Energy is seeking approval of $0.487 million and $0.582 million in 2008 and 2009 respectively, including approval to adjust diesel prices used in setting fuel costs to reflect current forecasts (from 60 cent per liter range approved in 2005 to forecast price of approximately $1.11 per litre in 2008 and $1.15 per litre in 2009)[24]. Prior to the 2008 test year, extra costs for generation due to diesel fuel prices in excess of 2005 Required Revenues and Related Matters hearing forecasts were not included in Yukon Energy's revenue requirement, but collected from customers directly through the Rider F Deferred Fuel Price Adjustment mechanism.

As noted in Exhibit B-10, fuel and purchased power were above forecast for 2008 largely due to fuel consumed in December 2008; this was discussed during cross examination (transcript pages 303-4) where it was noted that lower than normal temperatures combined with an outage caused by an equipment failure at the Aishihik plant were the drivers of this cost increase.[25]

As noted in response to YUB-YEC-1-30 (and in discussion at transcript page 235), and following past practice in Yukon (including YEC 2005 hearing and YECL 2008/2009 GRA) YEC is seeking approval of the fuel price forecast as initially filed in October 2008 and is not seeking to further update that forecast. The Application was filed using the best information available to YEC at the time. Fuel prices have been volatile since 2008 and are likely to remain uncertain for the future. Historically in the Yukon, a GRA fuel price forecast is typically retained as filed with any subsequent adjustments made, as required to deal with variations between actual prices paid and GRA forecasts, through the Rider F process.

CW-YEC-1-16(e) describes the impacts that would follow were the fuel price forecast updated to then current fuel price levels noting the combined impact would have an overall adverse impact on the revenues required from firm rates of approximately $0.448 million[26] (i.e., the overall rate decrease would be lower).

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[24] Yukon Energy's application proposes to update the prices for diesel fuel from that used in the 2005 GRA to forecast prices for 2008; Per Tab 3, page 3-4, forecast fuel prices for the test years are approximately $1.108 per litre for 2008 and $1.149 per litre for 2009 for Whitehorse.

[25] This discussion also noted other instances where fuel usage was required at pages 302-3; higher diesel usage (120 MWh) in April due to required maintenance at Mayo Hydro plant that consequently required diesel usage at Dawson; 175 MWh of diesel fuel usage was required in Whitehorse in May due to a vandalized insulator on transmission line L-170; 219 MWh was required in October due to WH3 governor tripping off at a time when WH4 was out of service due to repairs; in November diesel was required due to WH4 tripping off and causing and outage; a small amount of diesel was also run (10MWh) due to CSTP stage 1 coming into service.

[26] The 2009 rate reduction proposed by YEC in this case would be only $0.886 million, instead of the proposed $1.334 million.

3.1.2 Non-Fuel O&M Expenses

Yukon Energy is seeking approval to include in revenue requirement non-fuel O&M expenses totaling $12.362 million and $13.228 million respectively for 2008 and 2009. Responses to UCG-YEC-1-40(c), UCG-YEC-1-41(c), UCG-YEC-1-42(c), UCG-YEC-1-43(c), UCG-YEC-1-44(c), UCG-YEC-1-45(c), and UCG-YEC-1-46(c) detail the underlying factors driving variances between 2005 GRA and 2009 forecast costs in relation to employee complement history, Transmission costs, Distribution Costs, General Operating and Maintenance Costs,[27] Administration Costs,[28] Insurance and RFID provision[29] and Property Tax Costs respectively. Although no party filed evidence indicating any component of Yukon Energy's non-fuel O&M expense forecast was unreasonable, extensive additional evidence was provided by Yukon Energy in response to information requests and cross examination on the reasonableness of YEC's forecast.[30]

YEC's approach to forecasting labour and other expenses is described in response to YECL-YEC-1-36. Based on the approach utilized to forecast labour and non-labour expenses, the costs set out for O&M in Yukon Energy's revenue requirement are fair and reasonable. Detailed evidence in relation to key components of forecast non fuel O&M expenses is on the record as follows:

- **Employee Complement:** YEC's employee complement and the justification for added positions since 2005 are provided in response to LE-YEC-1-32; transmission labour costs and employee complement are detailed in CW-YEC-1-21 and LE-YEC-1-34 provides information and justification regarding why a full labour crew is required. Outside of the employee compliment additions, YEC's cost per employee has increased only 3.1% since the 2005 GRA, basically in line with inflation.
- **Vacancy Rate:** For 2008 and 2009, the vacancy rate assumptions used were 5% which equals approximately 4 FTEs. YEC reviewed the historical vacancy rates from 2005 to 2007. Staff turnover (and time it took to fill newly created positions) was reviewed and it was determined that the corporation was experiencing approximately a 5%, or 4 FTE's vacancy. YEC's forecast vacancy rate is consistent with the

[27] CW-YEC-1-21(a) discusses the cause of every year-over-year increase/decrease in each category of General Operating and Maintenance in Table 3.8 greater than 10%, as well as the cause for every increase/decrease from 2007 to 2008 for each category.

[28] CW-YEC-1-23(a) discusses the cause of every year-over-year increase/decrease in each category of Administration expense in Table 3.9 greater than 10%, as well as every increase/decrease from 2007 to 2008 for each category not already documented on pages 3-11 to 3-12 of the Application.

[29] YECL-YEC-1-29 deals in detail with the justification of charges to the RFID account in the test years.

[30] Furthermore, Exhibit B-10 provides at page B-1 that actual non-fuel operating and maintenance expenses in 2008 were above forecast by 11% or $1.375 million. Page B-2 and B-3 review material variances (greater than 10% as required by Board Order 2009-4).

methodology used by the Board in determining YECL's vacancy rate in Board Order 2009-2.[31]

- **Inflation Rate:** The forecast non-labour inflation rate used in the application is discussed in response to CW-YEC-1-20(b). Per that response, a 2% inflation increase was applied to 2009 spending. According to the Yukon Bureau of Statistics the annual average inflation rate in Whitehorse for 2007 was 2.5%. This is also less than the inflation amount approved by the Board for YECL in Order 2009-2.[32]

In addition, YEC's O&M expenses that were the subject of detailed interrogatories or cross-examination are addressed separately below.

- **Labour Costs** - Details with respect to the increase in labour costs and the amount of labour costs transferred to capital and deferred projects are provided in response to UCG-YEC-1-35(a).[33] As noted in page 3-6 of the Application, increases in labour expense make up 62% of the total increase from 2005 actuals to 2009 forecast; most of this increase occurred between 2005 and 2007 ($0.996 million), reflecting additional positions as well as negotiated step increases.
- **Non-Labour Costs** - Between 2005 Actual and 2009 forecast 38% of non-fuel O&M cost increases are related to non-labour items. This is an average annual increase since 2005 of only 3.2% a year on overall non-labour O&M costs which is in the range of inflation over the period. In terms of non-labour costs of specific functions:
- **Production Costs** – UCG-YEC-1-40(c) notes that Operations Supervisors costs were included in other functions in 2005 and that this approach changed. This change in allocation accounts for $84,000 of the forecast labour cost change from 2005 approved levels to 2009 forecast. Absent this change, the increase in labour costs is less than 3% over the period,[34] and remains consistent with actual levels of cost experienced between 2005 and 2007.

[31] At page 15 of Appendix A of Order 2009-2 it is noted that "the Board finds a vacancy rate of 3.5, the average actual vacancies for the period 2003 to 2007, to be reasonable for the test years. Therefore, the Board directs YECL in its refiling to reflect a vacancy rate of 3.5 FTEs for each of the test years.

[32] Page 16 of Appendix A of Order 2009-2 notes the following with regard to the determination of the non-labour inflation rate, "The Board finds it reasonable that the forecast non-labour inflation rate for 2008 and 2009 be 3.75%, which is calculated using a 50/50 weighting and inflation rates of 5.0% (Alberta) and 2.5% (Whitehorse). The Board therefore directs YECL in its refiling to reflect in its revenue requirement, an inflation rate of 3.75% for its O&M costs other than labour."

[33] Position titles and compensation amounts greater Than $100,000 (for actual 2005 to 2008 and forecast 2009) were also provided in UCG-YEC-1-35(b).

[34] Exhibit B-10 provides a 46% ($302,000) variance in production costs from 2008 forecast to actuals due largely to unforeseen safety and repair work required work Aishihik, Whitehorse and Mayo plants.

- **Transmission Costs** – UCG-YEC-1-41(c) notes the variance of $277,000 from 2005 to 2009 forecast is due to brushing costs for L169 and L170. The brushing program requirements and costs to be incurred in the test years are also discussed in responses to YUB-YEC-1-37(d) and (e), and LE-YEC-1-33.[35]
- **Distribution Costs** – UCG-YEC-1-42(c) remain basically at the same levels as 2005.[36]
- **General O&M** – General expenses are incurred with respect to transportation, communications, SCADA communications and maintenance of company owned properties. UCG-YEC-1-43(c) notes variances in 2009 forecast compared to 2005 approved amounts are due largely to higher transportation costs owing to higher fuel prices and higher costs for maintenance of company owned properties. Labour costs in the test years are forecast to be lower than the 2005-2007 levels.
- **Administration** – Non-labour costs of administration remain at approximately the same level as 2005 actuals. At page 3-11 of the Application, notable increases are attributed to information systems[37] and safety[38] which are offset by reductions in general administration and materials management.[39] UCG-YEC-1-44(c) and CW-YEC-1-23(a) note the reasons for variances in 2009 from 2005 approved amounts.

3.1.3 Insurance and Reserve for Injuries and Damages

Costs related to insurance and the Reserve for Injuries and Damages are set out in Table 3.10 at Tab 3 of the Application, and the operation of the reserve and approvals sought in this application are fully described at pages 3-13 to 3-14. YEC is seeking the following approvals related to the Reserve for Injuries and Damages:

- To apply $0.463 million of the remaining Faro Dewatering Account deferred regulatory liability amounts (related to earlier "dewatering sales" to the Faro mine site) against the current outstanding balance in the Yukon Energy Reserve for Injuries and Damages.
- To increase, starting in 2009, the ongoing annual appropriation to the Reserve for Injuries and Damages to $150,000 from the current $50,000 level.

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[35] Exhibit B-10 provides that actual transmission costs were 44% ($244,000) above forecast in 2008 due largely to the requirements to continue to maintain the system.
[36] Exhibit B-10 indicates there were no material variances from forecast in 2008.
[37] Funds allocated towards implementing recommendations that issued from the IT strategic Plan and Business Impact Assessment in order to put in place procedures necessary to support the IT Security Policy.
[38] In 2008 safety costs were forecast to remain within historical range; 2009 included costs for process to document safety procedures – a periodic requirement of Yukon Occupational Health and Safety Act and the Yukon Worker's Compensation Health and Safety Board.
[39] Application page 3-11.

No party filed evidence indicating that YEC's proposals in relation to the Reserve for Injuries and Damages to increase were unreasonable.[40] However, the following matters were raised and addressed in interrogatories:

- YUB-YEC-1-6 provides a continuity schedule of charges to the reserve from 2005 to 2008. UCG-YEC-1-45(a) provides an updated Table 3.10 which included 2005 allowed amounts; actual for 2008 were included in the updates provided in Exhibit B-10.
- YECL-YEC-1-29(a) describes briefly the process for making charges to the reserve and notes all charges are at the discretion of the CFO; Material variances in RFID costs between 2005 approved and 2009 forecast are discussed in the response to YECL-YEC-1-29(c).
- YECL-YEC-1-32 addresses deductibles in YEC's insurance policy, and CW-YEC-1-24(b) deals with how risk assessment and insurance requirements are addressed by YEC and notes YEC employs a professional insurance broker that specializes in utilities insurance, YEC provides an annual update to the broker who reviews the coverages and makes recommendations. The program is then marketed to key insurance providers and the broker gets quotations on costs of existing and enhanced coverages (where applicable).

During the hearing, counsel for YECL conducted cross examination (at transcript page 114-119) on the criteria used by YEC in relation to the RFID. YEC's evidence was that the CFO makes the determination regarding whether an item is charged to the reserve, with advice of a professional insurance broker for larger incidents (transcript page 117, lines 1-7).

With regard to established criteria for charging items to the account, Mr. Mollard confirmed that YEC has established criteria with regard to charging items to the reserve based on terms included in YEC's property insurance policy described at transcript page 114, lines 20-23 as follows, "the sudden and accidental loss of use of an object, which is defined in the policy as one of our assets." Further additional YEC evidence in relation to its criteria is as follows:

- A $1000 limit is used to define items that are considered material losses to be charged to the reserve (page 115 lines 6-8) and anything below this amount is considered immaterial and charged to maintenance. It was noted that this limit was not set in connection with the O&M budget and is in no manner connected to the

[40] Aside from UCG 45(d) (requesting internal reports or documents), no IRs no interrogatories were asked related to the basis for the increase in the appropriation from $50,000 to $150,000 in 2009.

O&M budget (page 118, line 1-4). In particular, Yukon Energy's O&M budgets are not set to recognize these potential costs.

- It was further noted that probability of the event occurring/recurring was generally not considered a criteria underlying whether or not it would be charged to the reserve (page 115 lines 21-25), and that sudden and accidental events generally did not lend themselves to being forecastable (page 116 line 8-11).
- Items cannot be charge to the reserve if the cause of the loss was normal wear and tear (page 116, lines 16-18).

3.2 RATE BASE, DEPRECIATION AND AMORTIZATION

3.2.1 Overview of Approval of Mid-Year 2009 and 2009 Forecast Rate Base

Yukon Energy is seeking approval of costs for capital works projects brought into service (or forecast to be brought into service in the test years) since the 2005 Required Revenues and Related Matters Application, as well as deferred costs (including deferred costs related to the current application) and working capital forecast to be included in rate base. Relevant major capital projects over $1 million are discussed in Tab 5 of the Application at pages 5-3 to 5-13. Relevant major deferred costs included in work in progress (for planning engineering, permitting and potential tendering activities as required for Mayo B hydro generation enhancement), other generation feasibility assessments, Western Copper connection and CSTP Stage Two are discussed at pages 5-19 to 5-21.

3.2.2 Depreciation and Amortization

Depreciation

YEC has in its application proposed no changes to depreciation rates and proposes to maintain the ASL method of depreciation as previously approved by the Board in Order 2005-12. There were few interrogatories and little discussion at the hearing related to the depreciation methodology used in the current application:

- UCG inquired as to whether YEC was relying on the study provided by Gannett-Fleming for the 2005 Required Revenues and Related Matters Applications (see UCG-YEC-1-47 and discussion on the transcript at page 403 to 405).
- The Board inquired in YUB-YEC-1-8 as to whether YEC had made any changes to its depreciation assumptions since Order 2005-12.

As noted in response to these interrogatories and in discussion at the hearing YEC has in its Application relied on the study previously provided by Gannett Fleming in 2005, and currently has no plans to update its depreciation study.

Amortization of Regulatory Costs

Yukon Energy is seeking approval to amortize expenses totalling $6.391 million[41] for 2008 and $6.930 million for 2009, including the following regulatory costs:

- In the Application filed October 2008 YEC initially sought approval for an estimated "placeholder" expense of $0.800 million related to costs for the current GRA Application that were anticipated to be incurred over 2008 and 2009. This place holder estimate was updated in response to YECL-YEC-1-28 Revised and in Exhibit B-10.
  - It was noted in YECL-YEC-1-28(a) Revised that, "the initial estimate provided when the Application was being prepared was based on the assumption that, given the previous review in 2005, the process would be more efficient and costs would be less than experienced at that time. This assumption did not bear out."
  - Based on current information the present forecast cost of the current GRA hearing process is now $1,100,000.[42] Exhibit B-10, page A-3 and A-4 proposes

[41] Page 3-16 of the Application notes $6.403 million for 2008; this number was adjusted downward for 2008 in Exhibit B-10 to reflect a shorter CSTP in service in 2008.

[42] Amortization of regulatory hearing costs was discussed in response to several interrogatories and in response to cross examination by YECL and Board Counsel at the oral hearing on May 5th and May 6th. The approach to amortization of regulatory hearing costs was further discussed and clarified in Undertaking #25 filed on May 15, 2009. The following is noted with regard to YEC's approach;

- As noted in undertaking #25, "rate case costs" incurred as part of YUB regulatory processes are not included in a specific permanent rate case reserve deferral account, and YEC has never sought, or received YUB approval to establish a permanent rate case deferral account similar to the approved RFID reserve account. This was also discussed in cross examination at transcript page 164, lines 10-16.
- Costs for completed rate cases (or other YUB hearing processes) are capitalized and amortized (as deferral costs) in accordance with Board Orders. It was noted on the transcript at page 127, lines 7-15 that these amounts have not had AFUDC applied to them while they are being deferred.
- The means of accounting for Rate Case costs were previously addressed in detail during the 2005 Required Reviews and Related Matters hearing. This was discussed on the transcript of the current proceeding at pages 163-164 where it was noted at page 163, lines 16 to 24: "Well, Mr. Keough, I'm having recollections of a very similar discussion in 2005 at that hearing in regards to hearing costs on basically the same issue. And the answer is -- is the same as it was then: Yukon Energy incurs hearing costs, amortizes them over a period or at a rate approved by this Board, and when there is no cost left to amortize, the amortizations stop." Further at page 164, lines 7-9, "It's a simple amortized cost, the same way as any other deferred cost in the cost structure".
- Similar to the discussion that occurred in 2005, counsel for YECL raised concern that the existing rates that are established will result in customers paying the 400,000 in 2010 and 2011, if those are not test years. In response Mr. Bowman noted (at page 164 lines 22-25 and page 165 lines 1-2: "2010's costs will be what 2010's costs will be", noting that "Rate reviews deal with the years in question, and in this regard, the end of

that the annual amortization of these costs remain at $0.4 million per year such that a forecast $0.3 million will remain to be amortized in 2010. See also discussion at transcript page 163 and 164.[43]

- Total incurred costs for various regulatory proceedings which have occurred since the 2005 Required Revenues and Related Matters (and have been previously approved by Board Orders as set out in Tab 6) proceeding as follows:
  - $0.643 million related to regulatory review of Yukon Energy's 2006-2025 Resource Plan, to be amortized over 10 years to be consistent with the anticipated frequency of full Resource Plan updates.
  - $0.243 million related to the regulatory review of the Minto Explorations Power Purchase Agreement, to be amortized over 12 years consistent with the currently anticipated economic life of the spur line connecting to the Minto Mine.
  - $0.185 million related to the regulatory review of the CSTP under Part 3 of the Public Utilities Act to be amortized over 45 years consistent with the approximate average life of the project assets.

3.3 RETURN ON RATE BASE (INTEREST COSTS AND ROE)

Yukon Energy's Application outlines the Utility's requested return on rate base (pages 3-15 to 3-21). The forecast return on rate base for 2008 and 2009 is $9.845 million and $10.724 million.[44] This return includes interest costs for the Corporation's debt, and a fair return on shareholder equity as directed under Order-in-Council 1998/32. There has been no change in the relative weighting of debt and equity in Yukon Energy's capital structure since the 2005 proceeding (since 1992, Yukon Energy has maintained a balance of 60% long term debt and 40% equity).[45]

amortizing your GRA costs is the same as amortizing any of these other studies you will see ending in Table 5.7." at page 165, lines 15-19 it was noted that "the application does not seek approval to do anything different than has been in the past. GRA costs amortized over the period it takes to amortize them off, given a rate of $400,000 a year."

YEC has fully explained the process historically used by the utilities in Yukon to amortize hearing and other deferred costs, noting it was is exactly the same as that approved by the YUB in all past hearings (including application to the year 1995, for both YEC and YECL which was not a test year) and used for all other deferred costs such as planning and study costs, overhauls, deferred downsizing amounts, relicencing amounts and dam safety costs. Costs incurred are collected in a deferral account until such time as they are "in-service" or ready to be amortized at which time they will be charged to income at a fixed rate over the appropriate number of years (for example 5 years for study costs, typically 2 or more years for rate hearing costs, the term of the licence for relicencing costs) and will stop being amortized once the deferred costs reach zero.

[43] Exhibit B-10, Page A-4 notes that these adjustments in 2008 and 2009 affect mid-year Rate base (schedule 1) as well as Amortization of deferred costs (Schedule 5) with the overall impact being a slight reduction in revenue requirement in each test year.

[44] As noted in Exhibit B-10 and discussed in the Opening Comments provided by YEC (Exhibit B-12).

[45] The response to CW-YEC-1-26 attaches the financial policy approved by Yukon Energy's Board at the December 18, 1992 meeting.

3.3.1 Interest Costs

As noted in UCG-YEC-1-50 Revised, Yukon Energy's practice with respect to dividends and issuances of long-term debt is to declare dividends out of equity and issue long-term debt annually, as required in order to maintain a 60% debt: 40% equity capital structure at year end, while retaining a minimum of cash in the utility outside of amounts required to finance the ongoing capital program. In accordance with the financial policy (attached to CW-YEC-1-26) interest rates attached to the YDC advances are the Long-Term Benchmark Canada Bond Yields for December 31 of the respective year plus 120 basis points.[46]

The cost of debt[47] is forecast to increase to 6.19% in 2009 up from a level of 5.18% in 2005. YEC's actual average weighted cost of debt and equity is discussed in response to UCG-YEC-1-51(b).

3.3.2 Return on Equity

Yukon Energy's Application requests Board approval for a fair return on equity of 8.64% in 2008 and 8.49% in 2009.[48] As in the 2005 Required Revenues and Related Matters filing (and similar to the approach approved recently for YECL), YEC is seeking approval of an ROE based on the ROE for a low-risk benchmark utility as determined by the BCUC for 2008 and for 2009. YEC explained its reliance on this approach and derivation of the ROE for 2009 in response to interrogatory YUB-YEC-1-15(d). In response to YUB-YEC-1-15(c), YEC provided the basis for continuing to use a risk premium of 52 basis points.

No material issues were raised by intervenors in cross examination at the hearing regarding the use of this approach or the use of the risk premium previously approved for YEC by the Board in Order 2005-12.

3.4 STABILIZATION MECHANISMS

3.4.1 Diesel Contingency Fund (DCF)

The DCF is discussed in Application at page 3-21 to 3-22. Further, the fund is described at transcript page 303 as follows:

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[46] YUB-YEC-1-11 notes that the terms of YDC loans and notes as listed in Schedule 13 of Tab 7 are provided Note 13 to the 2007 Financial Statements included in the Application at Tab 9, as well as the response to CW-YEC-1-26(a).

[47] CW-YEC-1-28 addresses how the mid-year cost of debt is calculated, and notes how the means of calculating mid-year debt is different than YECL's approach.

[48] LE-YEC-1-39 and YUB-YEC-1-15 both provide that BCUC Letter No. L-55-08 provides a 8.47% benchmark return on equity for a low risk utility. Considering the 0.52% risk premium proposed for Yukon Energy together with the 0.50% deduction directed by OIC 1998/32, the 2009 fair ROE for Yukon Energy is 8.49%.

> The diesel contingency fund is an ongoing trust item. I use the word "trust," because that's the way that effectively it's accounted for. It is an account that's been around for a long time. It was first set up under a different name, the low-water reserve fund. It became a diesel contingency fund in '96, '97. Its amounts held to deal with uncertainties related to water flow, in the event there was a very severe drought. The fund effectively pays for the diesel required to deal with that drought. In the meantime the cash that's in that fund is invested externally. It earns interest.

As noted at page 309, while there have been no amounts charged to the account recently, past experience suggests that in the event of a severe drought (even at today's load levels) Yukon could be required to burn diesel for baseload reasons.

3.5 REGULATORY COSTS ISSUES RAISED BY BOARD COUNSEL

One further issue relating to O&M costs (which also is related to costs included in major capital project costs) relates to Regulatory costs, more specifically, YEC's outside consultant costs.

During questioning from Board counsel, issues were raised relating to the magnitude of external consultant costs (more specifically InterGroup's charges to YEC over the last several years) and whether YEC should consider hiring in-house expertise related to activities presently provided by consultants. This issue was responded to both at the hearing (transcript, pp. 534-535) and in detail in Undertaking #25.

The evidence demonstrates that the costs incurred by YEC in relation to its external consultants are reasonable, and there is no evidence on the record that the costs in general were (or any specific cost was) imprudently incurred.

A summary of YEC's evidence on this issue is as follows:

- Board counsel's questioning appears to arise from a misunderstanding or confusion about the type and magnitude of external consultant costs that had been and will continue to be incurred by YEC outside of YUB rate regulation activities, (i.e. rate case and related costs).
- Most of the costs incurred in hiring external consultants related to non-rate or non-YUB related regulatory activities over the 2005/08 period such as environmental permitting, resource development, project development activities and other non-rate case related areas.
- In the specific case of InterGroup, for example, the work on major capital projects includes engaging in public and First Nation consultation, undertaking environmental

studies, compiling and completing the extensive documentation required for YESAB filings, an on-going work required to complete the review process (adequacy reviews, response to public and YESAB questions, etc.). Although YEC does have internal staff dealing with permitting and other related matters, YEC does not currently employ the expertise and/or the staffing levels to accomplish these activities. Increasing regulatory activity experienced by regulated utilities such as YEC have resulted in substantial expenditures involving external consultants and other specialists. The hiring of outside experts to undertake this type of work is not unique to YEC. It is the normal practice for utilities such as BC Hydro and Manitoba Hydro to retain external consultants as required to undertake these activities. Further, reasonable costs for hiring such expertise are appropriately included in rates in those jurisdictions.

- Depending on the nature of the expense, costs incurred to engage in regulatory activities are accounted for as capital costs (e.g. for major capital projects such as the CSTP and Mayo B project such costs would be included in project costs), or O&M costs (for e.g. regulatory costs incurred for minor capital projects, on-going water licensing monitoring and reporting, safety regulatory requirements, and other regulatory compliance or permitting activities normally included under administration).
- The difference in accounting for regulatory costs for capital project versus rate costs connected to a YUB-led review were discussed at pp. 543-544 of the transcript.
- A breakout of the O&M regulatory cost items forecast in the test years and a review of the regulatory costs included in capital projects are contained in Undertaking #25.

4.0 RATES

4.1 OVERVIEW

The Application proposes changes to retail firm rates for all customers of YEC and YECL, changes to one term of the secondary (interruptible) sales Rate Schedule 32 (this change does not affect rate revenues), and changes to wholesales Rate Schedule 42 affecting only YECL. In addition, in order to determine retail firm rate revenue requirements consistent with the Application's fuel price forecasts, adjustments are proposed to update the secondary sales baseline rates and to establish a baseline fixed Rider F rate for the industrial Rate Schedule 39. No changes are proposed to the actual rates charged to Rate Schedule 32 or Rate Schedule 39 customers.

The Application recognizes and conforms to the rate directive requirements of OIC 1995/90 (including requirements regarding equalized rates, runoff rates and wholesale rates), OIC 2007/94 (which fixes Industrial Rate Schedule 39 until after 2012) and OIC 2008/149 (which requires, prior to 2013, that rate adjustments apply equally, when measured as percentages, to all classes of retail customer).

It is understood that YEC's fuel price Rider F account will be reset as of January 1, 2008 to reflect the new YEC baseline diesel fuel price forecasts and secondary sales price forecasts set out in the Application. Such changes have already been made to reflect Board Order 2009-2 on the YECL GRA. As of March 2009, Rider F became zero (versus 1.86 cents per kWh when the Application was filed), and may well become negative in the near term in the event that actual diesel fuel prices remain below the GRA forecast fuel prices (transcript, page 452).

Finalization of YECL's GRA (Board Orders 2009-2 and 2009-5) and changes to Rider F result in a Revised Table 4.5 (see below) addressing the effective residential incremental runoff rates applicable in the Hydro and Large Diesel rate zone (similar updates would apply in other rate zones, and for other retail rate classes). The update confirms that the effective second block energy rate has been reduced as a result of the recent Rider F, G, J and R changes, thereby moving further away from the efficient price signal required to reflect incremental diesel generation costs (at 37.37 cents per kWh based on YEC's forecast fuel prices for 2009 in the Application; at about 24.8 cents per kW.h based on the actual diesel fuel prices in January 2009 (UCG-YEC-1-62(a)).

Table 4.5 Revised
Effective Residential 2nd Block Rate (Hydro and Large Diesel Zones) – Existing and Proposed Rates

	Actual Oct-08	Actual & YECL Compliance Jun-09	Actual & YECL Compliance Jan-10	YEC Proposed Jan-10
2nd Block Base Rate Charge ($/kW.h)	0.1045	0.1045	0.1045	0.1606
Rider F ($/kW.h)	0.0186	0	0	0
Rider J % applied to base rates	14.93%	11.45%	11.45%	14.93%
Rider R or G % applied to base rates	5.00%	4.15%	10.526%	10.526%
Total ($/kW.h) excluding Income Tax Rebate and GST	0.1439	0.1208	0.1275	0.2015

Yukon Energy also understands, through Board Order 2009-1 and Exhibit A-10, that it is the Board's desire that a joint YEC/YECL cost-of-service study now be undertaken and a that a joint YEC/YECL Phase II application be prepared for review by the Board. Yukon Energy has proposed to YECL that as soon as possible following this hearing, the two utilities meet to discuss and plan the joint YEC/YECL Phase II application.[49]

[49] See Exhibit B-13 and transcript pages 35-36 (re: letter to YECL), 592-596 (re: potential timing, priority rate design issues and past COS experience) and 401 (purpose and geographic scope of cost of service study).

All parties appear to recognize that some rate changes can and should be implemented as part of the current Application without waiting to complete the Phase II application and hearing process, including changes to pass on the firm rate reduction to retail customers, adjustments to bring Pelly Crossing into the hydro rate zone, changes to secondary sales baseline prices and the fixed industrial Rider F (as required to support the firm rate reductions), and likely the changes as proposed to Secondary Sale Rate Schedule 32. Intervenors IRs and cross exam (YECL, CW, UCG) have addressed at some length issues regarding proposed increases to residential base rates (increased runoff rate and related reduced first block energy rate) and YECL (cross exam) and the YUB (IR) have addressed the proposed Energy Reconciliation Adjustment (ERA) to wholesale Rate Schedule 42.

Recognizing the pending joint Phase II application for review by the Board, Yukon Energy submits that its rate proposals in the current Application are limited to matters required and feasible at this time in light of the firm rate revenue requirements for 2009, the bulk power system challenges to address emerging baseload diesel generation requirements on both grids, the current OICs directives, past practice in Yukon as to rate adjustments that do not require or rely on a cost of service study, and other practical limitations as to what Yukon Energy can propose without the need for joint review and development with YECL.

4.2 RETAIL FIRM RATE REVENUE REQUIREMENTS AND RIDER U REDUCTIONS TO RETAIL FIRM RATES

Yukon Energy's forecasts of retail firm rate revenues requirements, and related reductions required to existing retail firm rate forecast revenues, are soundly based and have not been challenged by any party to date (beyond issues pertaining to the revenue requirement as discussed in section 3 of this argument). Accordingly, the Board should approve the following:

- Yukon Energy's forecast rate revenue requirements from firm rates of $27.564 million for 2008 and $29.969 million for 2009, as set out in Table 4.1 of the Application as updated in Attachment A of Exhibit B-10. These requirements for each test year reflect the overall forecast revenue requirements less forecast Non-Rate Revenues and forecast rate revenues from secondary sales at the adjusted secondary sales baseline rates as proposed in the Application.[50] Subject to the issues as noted regarding the forecast revenue requirements, this approach and the forecasts of Non-Rate Revenues and secondary sales rate revenues (including the proposed new baseline rates for secondary sales) were not challenged by any party during the hearing.

[50] The new secondary sales baseline rates to retail and wholesale customers are set out at page 4-5 of the Application, and in effect reflect actual rates charged in each quarter of 2008 and extension through 2009 of the actual rates charged in the last quarter of 2008.

- Yukon Energy's forecast revenues at existing firm rates of $27.594 million for 2008 and $31.300 million for 2009, as updated in Table 4.1 of Attachment A, Exhibit B-10. These forecasts include Rider J revenue from YEC and YECL (based on the Rider J in place when the Application was filed) and the proposed fixed component of the Industrial Rider F as updated in Attachment A of Exhibit B-10. These forecasts, including the fixed component of the Industrial Rider F, were not challenged by any party during the hearing.
- Based on the above, the proposed retail firm rate revenue reduction of $0.03 million for 2008 and $1.331 million for 2009, as set out in Table 4.1 of Attachment A, Exhibit B-10.
- Final revenue adjustments for 2008 through approval, as final, the Rider J reduction of 3.48% for December 2008 and the Faro Dewatering Fund withdrawal of $0.087 million as set out in Exhibit B-10.

The proposed Rider U focuses the remaining 2009 retail firm rate reduction on first block energy rates, thereby ensuring that second block or runoff rates do not move further away from efficient price signals and that rate reductions benefits for the majority of YEC and YECL retail customers will be materially enhanced.

Mr. Morrison explained (transcript pages 37-39) that Yukon Energy, as the main generator and transmitter of electrical energy in Yukon, has a vital interest in ensuring that retail runoff rates are once again being adjusted upward today to reflect incremental diesel generation costs. He noted, however, that second block runoff rate changes currently are going in the wrong direction – that runoff rates today have already gone down due to YEC's interim rate rider J reduction and the recent change to reset Rider F to zero. These observations are re-enforced by the Revised Table 4.5 (see section 4.1 of this argument) which shows how second block rates went down after fall 2008, and confirms that even when YECL's full fuel price rate adjustment is in place though an increased Rider R by January 2010, second block rates will still be lower than in fall 2008.

Yukon Energy submits that, contrary to an across the board Rider J reduction, the proposed Rider U implements the required firm rate reduction for retail customers in a manner that is consistent with OIC 1995/90 runoff retail rate directives as well as OIC 2008/149 restrictions, and avoids moving second block runoff rates still further away from promoting economy and efficiency. Further, Rider U as proposed will apply consistently to all retail rate classes, and will materially enhance the rate reduction benefits secured today by the majority of retail ratepayers (who only use first block energy).

4.3 BEGIN TO RESTORE EFFICIENT RESIDENTIAL PRICE SIGNALS

The Application's increase in the residential second block rates provides a modest first step that is feasible today to begin the process of restoring efficient price signals for residential electricity sales in Yukon. This proposal will also significantly enhance rate reduction benefits for the vast majority of residential customers throughout Yukon (transcript page 28),[51] and make progress towards reflecting the principles of economy and efficiency previously established by the Board and required by OIC 1995/90.

Concerns raised by Yukon Energy with regard to establishing adequate runout rates go well beyond the need to promote the principles of economy and efficiency in order to comply with past precedents and government OICs. Runout rates that poorly reflect current fuel prices (as approved for the new GRA revenue requirements) will have a negative impact on the earnings of the utilities when second block sales increases fail to secure sufficient revenues to offset incremental diesel generation costs (as discussed on the transcript with regard to the wholesale rate).

Yukon Energy has explained that it was not feasible at this time, without joint review with YECL, for YEC to propose similar modest increases to general service runoff rates. The issues in this regard relate to the relatively high volume of general service sales in the second block versus the first block (transcript pages 596-597).

This proposal has been subject to considerable discussion and review both in interrogatories and during cross examination at the hearing.

- YECL's concerns related mainly to lack of consultation and approach (orderly vs. piece meal), noting concerns regarding whether or not it would be more orderly to adopt an approach that would involve both utilities, consultation, and consideration of all customers rather than isolating one component of rate design and changing it in isolation. Transcript page 69-74: Discussion of Orderly Approach vs. Piecemeal approach (transcript page 68 and following); YECL asked one interrogatory related to the issue related to electric heating and consultation related to energy planning.
- CW asked a number of interrogatories related to rate restructuring within rate classes and efficiency price signals underlying the rate (CW-YEC-1-11 to CW-YEC-1-13) and also addressed issues related to runout rates in its cross-examination (at pages 268 through 283- focused on efficient price signals and conservation).

[51] The increased revenue for each customer class from the increased second block rate is all used to reduce first block energy rates for that same customer class (in order to conform with OIC 2008/149). As demonstrated at page 3 of the Application, 76.6% of the 2.12 cents per kWh overall reduction proposed for first block residential energy rates would be due to rebate of added revenues from the higher second block rate.

- UCG also asked a number of interrogatories related to runout rates, rate rebalancing and cost of service including the following: UCG-YEC-1-2(c), UCG-YEC-1-5, UCG-YEC-1-13, UCG-YEC-1-15, and UCG-YEC-1-95; in cross-examination at page 383 to 396 dealing primarily with efficiency incentive underlying change and billing impact tables included in the Application.
- The YUB also asked interrogatories regarding consultation, runout rate design and runout rate principles relied upon by YEC in implementing the changes to runout rate included in the application (see YUB-YEC-1-21 which attaches the 1992 Report to the Minister related to cost of service and rate design which establishes the rate design principles that used to set runout rates in the 1993 and 1996/97 GRA and relied upon in the current Application). (Transcript pages 596-98 provide discussion of type of rate design issues and options that YEC intends to bring to the table in subsequent proceeding, which included review of rate design changes needed to increase runoff rates for general service customer classes).

As noted earlier, the opening comments provided by Mr. Morrison noted that "leaving aside OIC rate directions on this matter,[52] as well as past history,[53] Yukon Energy has a vital interest in ensuring that retail runoff rates are once again being adjusted upward today to reflect incremental diesel generation costs". YEC has not raised this as a new concern, but noted issues and concerns regarding the need to adjust runout rates as far back as 2005 when seeking a review of its revenue requirement after a long absence from regulation (Exhibit B-12). The following points are noted with regard to the urgent need to address this growing concern:

- Current diesel prices are well above the levels assumed in the current base rates which reflect diesel fuel price forecasts included in the 1996/97 GRA. As noted in Tab 4, pages 4-10 to 4-12, the fuel price forecast at the time of the 1996/97 GRA was in the 30 cents/litre range, while the current fuel price forecast for YEC is $1.17/litre. Current runout blocks based on 1996/97 fuel prices cannot in any fashion represent the principles of economy and efficiency adopted by the Board in its 1992 Report to the Minster regarding cost of service and rate design and implemented in practice in Orders 1993-8 and 1996-7.

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[52] Rate Policy Directive OIC 1995/90 (section 4(3) establishes that the Board is required to "fix runoff rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency".

[53] The Board's definition of economy and efficiency is provided in the 1992 Report to the Minster filed as Attachment 1 to YUB-YEC-1-21(b) at page 43, "The Board considers the efficient use of electricity to be the optimal use of electricity over time, where consumers are making rational decisions regarding the future and current use of electricity." The Board noted at page 46 that to promote "economy and efficiency" runout rates "should reflect short-run incremental costs in each of the rate zones as specified in the OIC and fixed costs incurred by companies should be recovered by demand charges, fixed charges and energy charges in the first energy block".

- Concerns related to runout rates based on essentially anachronistic fuel prices are apparent if compared to runout rates calculated using current fuel prices are used to calculate runout rates using the same approach approved during the 1996/97 GRA. As set out and described at pages 4-10 and 4-11 of the Application, the current runout rate for residential customers should be 37.37 cents/kWh as opposed to the fall 2008 effective rate of approximately 14.39 cents/kWh based on 1996/97 fuel prices, or the forecast January 2010 effective rate of 12.75 cents/kW.h (Revised Table 4.5 based only on YECL's new rates). With the material changes in fuel prices since 1996/97, the current runout rates simply do not provide any efficiency signal and do not represent the principles of economy and efficiency established by the Board pursuant to direction provided by rate policy OICs.

Piecemeal Approach to Rate Design

At transcript page 70, lines 20-24, Counsel for YECL noted YEC was proposing to change the runout rate for only one of the classes but not the other class, describing this as a "piecemeal approach" to rate design. It is YEC's position that this is not a "piecemeal" approach as asserted, but a necessary and required measure to be taken as soon as possible to begin to address the material concerns that arise from runout rates that no longer bear any relation to incremental costs of diesel and that are continuing to move in the wrong direction.

As noted at page 70, lines 1 to 9, YEC has brought an Application for review that attempts to deal with issues "as it best can in an orderly manner." As discussed in the Application at page 4-13 and page 4-14, and in discussion on the transcript at pages 70-72, YEC has identified the need to address runout block rates as an urgent matter to be addressed to ensure that runout block rates continue to reflect principles of economy and efficiency, and to ensure that Wholesale Rate 42 and the ERA continue to function appropriate and ensure YEC is held whole (see discussion at transcript page 58-65).

Given runout rates are now based on diesel fuel prices that were current in 1996/97, necessary adjustments are required at this time. Yukon Energy is seeking only modest adjustments to runout rates for residential customers based on previously approved and reviewed principles. As noted in response to YUB-YEC-1-21 the principles for determining the rates are long established and have been previously reviewed by the Board.

These modest adjustments are considered feasible at this time due to the fact that the minority of sales for residential class are at the second block (see table 4.9 of the Application which demonstrates that less than 20% of the non-government residential energy is sold in Yukon at second block rates). It was not considered feasible to address general service runout rates due to the fact that the class is dominated by sales in the second block (approximately 71% non-government sales);[54] the simple adjustments included in the Application for the residential class would effectively result negative first block rates for this class (see page 597). As noted by Mr. Osler at page 71-72, in order to address runout block rate issues for the general service class, measures such as splitting the class into further blocks would need to be considered, it was noted, "That is not something that Yukon Energy would ever try and do on its own. It would like to do it in conjunction with and cooperation of YECL".

Modest adjustments for the residential class are also feasible in light of the recent OIC direction 2008/149; as noted on the transcript at page 71, lines 11-15 the current restrictions are not unusual and "we have had the same situation in the early '90s for all of our rate cases that the two companies deal with the Utility Board on, and we certainly adjusted runout rates at that time."

Yukon Energy has in its Application made its best efforts to address the priority issues and the realities as Yukon Energy sees them. It has put forward its best proposals in the circumstances based on its significant concerns regarding this issue.

4.4 WHOLESALE RATES

Yukon Energy's firm rate revenues primarily arise from the wholesale rate charged to YECL; the structure of this rate must also meet the requirements of Section 7 of OIC 1995/90 and specifically provide for the following:

- The wholesale rate must "be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers"; and
- The wholesale rate "shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power customers as specified herein."

Required adjustments to Rate Schedule 42 Primary Wholesale as applied for are discussed at page 4-17 and 4-18 of the Application.[55] The concept of the Energy Reconciliation Account (ERA) was discussed at pages 58-59:

[54] At page 72, lines 8-11 it is noted that for general service class most sales are in the second rate block. Lines 11-18 note consequences of increasing the second block rate for this rate class in these circumstances: "if we were to start increasing the runout rate in the second rate block, we're affecting a very large volume in the rate class of the sales." It was noted that this concern was last discussed approximately a decade ago and that it may be an appropriate time to begin to discuss subdividing some of the rate block for this customer class. At lines 19-22 it was noted that "that is not something that Yukon Energy would ever try and do on its own. It would like to do it in conjunction with and cooperation of YECL".

[55] Yukon Energy is seeking approval to increase the Wholesale Rate (rate Schedule 42) charged to YECL throughout Yukon by 0.011 cents/kWh (from 6.840 cents/kWh to 6.851 cents/kWH) commencing concurrent with residential base

> The concept of the ERA, energy reconciliation adjustment, is to deal with what happens if there is a change from the forecast used to set the wholesale rate in a GRA, because the wholesale rate is just an average of all the forecast elements.
>
> The ERA concept arose when diesel was on the margin in the '90s all year round. If Yukon Energy in fact had to increase its generation requirements beyond what had been forecast and had to, say, provide an extra 10 percent, which I think is the basis for this example, of energy to Yukon Electrical, it had to use diesel to run it. You would be paying the cost of the diesel; you wanted to make sure it was getting it back, it wasn't charging YECL only an average lower rate.

Per YUB-YEC-1-22(a), "the level of the ERA needs to be set consistent with the price of diesel fuel in Yukon Energy's Revenue Requirement" and "even with acceptance of all residential runoff rates as proposed in the Application...Yukon Energy would be severely prejudiced when diesel generation for whatever reason becomes needed to supply wholesale load growth." This is due to the fact that the current proposed adjustments do not fully reflect current incremental diesel prices (as included in YEC's 2009 revenue requirement) at 37.37 cents/kWh.

The current Rate Schedule 42 (approved in the 1996/97 GRA) needs to be amended to establish an ERA charge not tied to the current approved run out rate for non-government residential service in the Hydro zone since the current runout rate of about 12 cents/kWh (Revised Table 4.5) is materially lower than the 37.37 cent/kWh rate that would apply for Yukon energy's costs.

As noted in discussion at page 67-68, runout rates that do not adequately reflect current diesel prices need to be addressed, not simply to ensure that the principles of economy and efficiency as determined by the Board continue to be reflected in rates, but to ensure that as Yukon returns to a state where diesel is once again "on the margin[56]", Yukon Energy continues to collect its revenue requirement. The material impact of runout rates that poorly reflect incremental costs

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rate changes in order to maintain revenue neutrality to YECL with respect to base rate revisions. Yukon Energy is also seeking approval to adjust the rate established for the Energy Reconciliation Adjustment provisions of Rate Schedule 42 to 37.37 cents/kWh using the same principles established in the 1996/97 GRA to reflect the current forecast incremental cost of diesel generation on WAF.

[56] This was defined on the transcript at page 55-56," In simple terms, it means that YEC, let's take the Whitehorse-Aishihik-Faro grid as the focal point, because I think your example is focused on that, if I am not mistaken, Mr. Keough. YEC is faced with generation requirements such that it has to run diesel, not just for a few moments of peaking but throughout most, if not all, of the year. We call that on the margin for the year base-load diesel generation. The concept of the margin means that it's the last source of generation that the utility is relying upon in order to meet the load requirements. And in Yukon we either use for generation hydro or wind, or when we can't use that anymore, we rely on diesel, and we say it's "on the margin."

was highlighted during the cross-examination provided by YECL's Counsel related to YEC's requested adjustments to rate schedule 42. The following key points in this regard were noted:

- The wholesale rate is fundamental to Yukon Energy's revenue requirement and ability to recover its costs. Incremental rates are fundamental to the ability of each utility to try and match costs to serving load for incremental changes beyond its forecasts.
- It was noted that these were not rate design matters separate from Yukon Energy's revenue requirement that could wait for a subsequent review, and are "fundamental revenue requirement matters" that are quite separate from rate design matters that would be discussed during a phase 2 review.
- It was noted that it is best to deal with matters that fundamentally affect revenue requirement when dealing with revenue requirements and the ability to keep each company whole.

Exhibit C1-9 prepared by YECL provided two scenarios related to Wholesale Rate schedule 42. It was clarified at page 57 that scenario 1 of the exhibit filed by YECL (purported to depict the existing rates, and if diesel were on the margin and Yukon Electrical sales or load was above forecast) did not accurately reflect existing rates due to the fact it did not reflect the updated fuel prices for YEC included in its 2005 Required Revenues and Related Matters Application (page 58).[57]

At page 62, lines 20-25, it was noted that (based on the fact scenario presented[58] and using existing rates), "as the rate presently exists coming out of 2005, where no change is made to the wholesale rate schedule, Yukon Electrical today would be required to pay 277,949, while YEC would incur costs of 536,698".

Scenario 2 in Exhibit C1-9 reflects the fuel price that is in the current GRA from Yukon Energy. The example demonstrates that "if the Board approves that forecast and approves Rate 42 as proposed, if Yukon Energy had to run diesel in the margin, its cost would be recovered from

[57] Page 61 notes, "the matching of the revenue with the cost, is the way that the ERA charge was developed in 1997, and it reflects YEC's fuel prices from 1997 and the rate that existed in 1997." As noted at page 62, "in 2005, YEC rebased its fuel prices. That earlier [1996/97 GRA] number was based about 30 cents a litre, and in 2005 they were up to approximately 56 cents a litre."

[58] Mr. Osler provided the following qualifications regarding the facts scenario as presented, "I think the math is -- if you accept all the assumptions, the math is fine. I would comment that for those of us who are involved in the history of this, I don't think that Richard Stout from ATCO or myself looked at it as incremental would necessarily be distributed the way you have assumed. I think the basic ERA approach assumed that, generally speaking, the incremental volumes would tend to be on the second block, in which case the math would change. You would be closer to the 10.45 cent revenue to capture, rather than the lower number."

YECL as per the original intent of the ERA". The underlying point is that the fuel and O&M costs incurred to supply extra load (whether incurred in Watson Lake or on the WAF system) must be recovered through rates by either YEC or YECL. If the runout rate is not appropriate, the company incurring the cost will be hit. The ERA simply transfers where the hit is, i.e., from Yukon Energy to Yukon Electrical (the utility primarily responsible for retail customers) (page 67).

In summary, the amended rate Schedule 42 ERA is fair and necessary to protect YEC in the event that diesel is on the margin for WAF and/or MD, and there is no reasonable basis or need to delay approval this rate adjustment until the Phase II hearing process.

4.5 SECONDARY SALES RATE DESIGN

Yukon Energy is seeking approval for adjustments to the secondary energy rates (Rate Schedule 32) to adjust the terms of Rate schedule 32 interruptions, such that future diesel requirements are to be reviewed based on five day weather and load forecasts rather than the current seven day forecasts.

CW-YEC-1-10 discusses the rationale underlying the use of the 5 day forecast (instead of the 7 day forecast;[59] the evidence relied upon by YEC in asserting that there will be no material effect on the amount of time secondary energy is to be made available as a result of changing to the 5 day forecast period, and overall the value of making this change. In sum, at the time of filing the Application there was no readily available 7 day forecast, which required Yukon Energy to extrapolate from available 5 day forecasts. The addition of a 6th and 7th day for the purposes of forecasting secondary sales interruptions rarely if ever drives the need to trigger a 24 hour interruption notice. The change is solely added to relieve Yukon Energy of having to extrapolate from the Environment Canada weather forecast to extend it to 7 days, when Environment Canada is only prepared to forecast 5 days out.

With regard to secondary energy revenue amounts for the GRA, Yukon Energy has not updated the secondary sales rate forecast from that used in Application filed October 2008. CW-YEC-1-16(e) noted the impacts that would follow were the fuel price included in the application to be updated; the combined impact of current lower fuel prices would have an overall adverse impact on the revenues required from firm rates of approximately $0.448 million.[60] As summarized therein:

[59] YUB-YEC-1-18 provides discussion regarding the initial use of the day forecast as approved in 2005.

[60] The 2009 rate reduction proposed by YEC in this case would be only $0.886 million, instead of the proposed $1.334 million.

- The cost of fuel in 2009[61] would be expected to be approximately $0.180 million lower than set out in the application.
- Current secondary sales prices would be reduced (at the retail level) 7.8 cents/kW.h for January-March 2009 and 6.3 cents/kW.h for April-June2009. The reduction in secondary sales revenues were the 6.3 cents/kWh price to be used for the year would be $0.458 million.

4.6 MAJOR INDUSTRIAL FIRM RATES

Exhibit B-10 provided an update to the industrial "fixed" Rider F to reflect final approvals for fuel price per litre provided in YECL's GRA proceeding[62] (at pages A-2 to A-3). CW-YEC-1-16(e) and Page A-3 notes that the lower fuel price of 96 cents/kWh approved in YECL's GRA application decreases the fixed Rider F rate from 0.585 cents/kWh to 0.109 cents/kWh. This results in a decline in industrial revenues from fixed Rider F in 2009 (from $0.170 million to $0.032 million).

5.0 CAPITAL PROJECTS

The Application in Tab 5 addresses capital projects under two headings: capital works (spending on property, plant and equipment) and deferred costs (includes planning and feasibility study costs, licensing and other non-YUB regulatory costs that are to be amortized over several years, and YUB regulatory or rate case costs).

5.1 CAPITAL WORKS: MAJOR PROJECTS OVER $1 MILLION

Intervenor and Board IRs and cross exam addressed at some length the Application's five major capital works projects over $1 million brought into service (or forecast to be brought into service) since the 2005 Required Revenues and Related Matters Application. The issues arising are addressed separately below for each of these projects.

A general issue addressed in cross exam by counsel for YECL and the Board[63] relates to the Board's prior review of Yukon Energy's 20-Year Resource Plan and the commitment by Yukon Energy to seek YUB review, prior to construction, of any major new capital projects over $3 million. In response, Yukon Energy has reviewed its ongoing efforts to work within the current legislative framework (which does not provide the YUB with any mandate to approve capital

[61] The response notes the current wholesale diesel fuel prices for new purchases (January 22, 2009): Faro 77.27; Mayo 78.01 Dawson 79.89 and Whitehorse 73.93

[62] Since filing the GRA Application, Board Order 2009-2 accepted YECL's GRA forecast diesel fuel price for 2009 averaging 96 cents/kWH.

[63] YECL counsel reviewed this with YEC at Transcript pages 74 to 80. Board counsel reviewed these matters with YEC at Transcript at pages 561 to 566.

projects for Yukon Energy or YECL) to seek such YUB review of major capital projects prior to construction. Yukon Energy confirmed that, as part of such efforts, Chapter 4 of its 20-Year Resource Plan had set out major near term capital projects for Board review and recommendations prior to construction, and that Yukon Energy was relying in this Application on the Board's prior reviews and recommendations to the Yukon Government with regard to both the 20-Year Resource Plan and the CSTP Part 3 hearings.

5.1.1 Carmacks-Stewart Transmission Project Stage 1

Project Justification and Prior Regulatory Reviews: A complete review of the history and series of regulatory reviews the Carmacks-Stewart transmission Project (CSTP) Stage 1 has been subject to since it was initially reviewed during the 2006 Resource Plan hearing is provided in the Application at pages 5-3 to 5-7. As set out in the Application and in response to YECL-YEC-1-11(d)[64], this project has been subject to rigourous public review and scrutiny including three separate reviews by the YUB (the Resource Plan hearing, the PPA Review and the Part 3 Hearing review) as well as an assessment of the environmental and socio-economic impacts by the Executive Committee of YESAB as required by the YESAA. Subsequent to each YUB review of the CSTP, the YUB has recommended the project proceed provided ratepayers would not be adversely affected.

Yukon Energy submits that these prior processes have fully reviewed and assessed the need and justification for the project in light of Yukon Energy's capacity planning criteria and near term requirements and opportunities, as well as alternatives to the project (as discussed during the Resource Plan hearing and in the Part 3 Application).

Interrogatories provided during the current GRA process confirm the benefits that have been secured for ratepayers through this project enabling the commencement of service to Minto Mine through the PPA with Minto. In sum, ratepayers have not been adversely affected by the completion of Stage 1 CSTP, but have received net benefits through the provision of grid service to Minto mine and Pelly Crossing (as evidenced by the rate reductions proposed in the Application).

Continued Net Benefits to Ratepayers: Page 5-7 of the Application indicates the net capital cost to Yukon Energy of the project being brought into service in 2008 is forecast at $3.744 million (as compared to zero net cost as forecast in the Part 3 hearing). Despite costs increasing beyond the high forecast indicated previously at the Part 3 hearing, the determination was made

[64] The response to YECL-YEC-1-11(d) references in full all information on the public record and available for review by the YUB and others that supports the need and justification for the project and the essential case that proceeding with the project will not adversely affect ratepayers, but provide net benefits through additional firm industrial sales provided to Minto over the life of the Mine as well as through the completion of long term transmission infrastructure that will generally benefit ratepayers for years to come.

by Yukon Energy to proceed with the project due to the overall net benefits remaining to ratepayers. YUB-YEC-1-36(a) provides a detailed assessment of the impact of CSTP on the YEC retail rate revenue requirement and indicates as follows:

- While the absolute amount of the revenue requirement would be lower without the Minto connection in service (due to removal of the CSTP net cost), the overall net impact on ratepayers without CSTP Stage 1 would be the requirement for a rate increase to meet the revenue requirement due to the materially decreased sales volumes absent the Minto and Pelly Crossing connections (31,323 MW.h lower total sales in 2009);
- Absent the additional revenues provided through grid service to Minto mine and Pelly Crossing through completion of CSTP Stage 1, Yukon Energy’s retail rate revenue requirement would be $0.567 million and $2.572 million higher in 2008 and 2009 respectively. Without CSTP Stage 1 Yukon Energy’s retail rate revenue requirement would require a firm retail rate increase in 2009 of $1.238 million (+3.23% if applied as an across-the-board retail rate rider).

Justification of inclusion of costs in Rate base as prudent expense: UCG-YEC-1-73(f) and (g) question the revenue requirement impact of the CSTP Stage 1 project in 2008 and 2009 given prior indications that the project would bring additional revenues with no capital costs and insignificant operating costs.

During the Part 3 hearing, YEC was forthright about the possibility of a revenue requirement impact owing to cost increases in excess of contributions. This was acknowledged by the Board in its report to the Minister regarding the Part 3 hearing. While costs have increased, YEC has demonstrated prudent management of costs and has successfully completed, under very challenging conditions, a project that will provide short-term and long term system benefits and rate benefits as evidenced by the rate reduction proposed in the current Application.

Cost Increases, Scope Changes and Project Management: LE-YEC-1-46 provides a detailed cost breakdown of the original CSTP Stage One budget and current (not yet then finalized) CSTP Stage One budget, and LE-YEC-1-47 provides a similar detailed cost breakdown for the Minto spur. Exhibit B-20 filed during the hearing provides an overview of initial cost estimates (as reviewed in the Resource Plan hearing in November 2006 and the Part 3 hearing in April/May 2007), construction budgets (as approved by YEC’s Board in September 2007), and final costs for CSTP Stage 1, noting when the estimates changed and the quantum of change. The following key points are noted with regard to the escalations in cost from the preliminary estimates initially reviewed during the Resource Plan hearing to the final costs (as of February 2009).

- The original cost estimate of CSTP Stage 1 in the Resource Plan hearing was $22.6 million; the original cost estimate of the Minto Spur in the Resource Plan hearing was $3.8 million; costs provided at that time included a range (low to high estimates); as then noted, these estimates were provided in advance of preliminary engineering.
- In September 2007, Yukon Energy's Board approved CSTP Stage 1 budget costs ($27.8 million) which included tenders for most items (but did not include tendered costs for substations); these costs did not include the additional Tatchun re-route costs subsequently required due route changes as directed in the final YESAB recommendations. Yukon Energy's Board approved budget costs for the Minto Spur ($8.8 million) which included tenders for most items (but did not include tendered costs for substations); these costs did not include the additional Yukon River crossing re-route costs subsequently required due route changes as directed in the final YESAB recommendations.

The final cost of the CSTP Stage 1 is approximately $29.7 million, (including $1.8 million in additional costs for the Tatchun reroute as necessary due to the YESAB review process);[65] absent the Tatchun reroute, final CSTP Stage 1 costs would be approximately $27.9 million. The final cost of the Minto Spur is approximately $10.8 million (includes any changes as necessary due to YESAB process). Absent such changes, the final cost would be $10.582 million. Pursuant to the PPA, Minto is paying all of the spur costs; this was confirmed on the transcript at page 573, line 7. [66]

As reviewed during cross examination with YECL counsel, the key difference between cost estimates as reviewed by the YUB in the Resource Plan hearing, the PPA hearing, and the Part 3 hearing, and the budget cost numbers the YEC Board approved in September 2007 was the additional considerations arising from the preliminary engineering cost estimates as provided to the YEC Board in June 2007[67]. Under the risk management approach taken by Yukon Energy with regard to the project, YEC did not want to undertake costly commitments for preliminary engineering until it had a PPA with Minto and the YUB's Resource Plan report recommendations. Accordingly, Yukon Energy did not engage the engineering consultants to prepare preliminary

[65] This significantly affected costs since the line moved from ground that was accessible by some vehicle, tract or otherwise, to ground that required every pole we put in was put in with a helicopter. This was discussed on the transcript at page 175-76.

[66] Differences between preliminary estimates and final costs were based on the following factors as discussed at page 174-75; at the time of the Resource Plan hearing, only preliminary information on the spur line was available, and there was an assumption made at that the cost of a smaller line, in terms of the line and the poles, would be significantly different than the cost of the main line. These estimates were also made prior to substation costs being tendered. It was noted that this construction occurred at a time where it was difficult to get contractors, men and equipment and the price of materials was inflated.

[67] Undertaking #26 reviews CSTP Stage 1 scope changes (and related cost impacts) arising from the preliminary engineering as regards substation requirements at Pelly Crossing, Carmacks and Minto Landing.

engineering and related cost estimates until March of 2007, and did not put out a tender for that engineering until January or early February of 2007. As a result, the preliminary engineering cost estimate information could not be available any faster than it was. (Transcript, pages 178-182).

Subsequent to the preliminary engineering cost estimates, and prior to committing in September 2007 to proceed with construction subject to securing final permits, Yukon Energy secured tendered costs for all major cost elements of the project other than substation costs. These tendered cost estimates were reasonably consistent with the preliminary engineering cost estimates. As reviewed in Exhibit B-20 and responses to IRs (YECL-YEC 1-9(b), YUB-YEC 1-39(a), and YUB-YEC 1-40(a)), cost changes thereafter were due primarily to additional costs issuing from YESAB scope change (unanticipated costs beyond YEC's ability to control), and additional costs arising from final substation costs as tendered in spring 2008.

Yukon Energy submits that costs for the CSTP Stage 1 project were prudently incurred and necessary for the project to be completed in accordance as required in 2008 and under challenging market conditions, and accordingly should be approved by the Board.

Preliminary Estimates Reviewed by YUB were Reasonable

Both counsel for YECL and Board counsel have questioned the value or basis for the preliminary estimates provided by YEC to the YUB for review at the Resource Plan hearing. In response, the following has been noted with regard to these estimates:

- As noted above, YEC elected to secure key items such as the PPA and Part 3 review prior to committing to the material costs involved in preliminary and final engineering. The information provided to the Board for review at the time of the Resource Plan hearing, as well as the Part 3 hearing, was the best information available at that time, and the Board had sufficient information to review the need, alternatives, risks and benefits of the project.
- In seeking Board review and recommendations based on costs that did not include preliminary engineering, YEC weighed the risks against the costs and determined that it would be better to proceed with regulatory reviews without preliminary engineering[68]. Mr. Osler noted, "It is a classic example of risk, cost. Information costs money to get, when do you get it. If we had spent the money on the preliminary engineering before we came to the Board and resource plan, we would have had better information. But if the

[68] YUB-YEC-1-39(c) notes that the project was planned through using a "phased approach whereby the [YEC] Board could review results at defined decision points prior to putting more budget dollars at risk." One key decision point was the September 2007 meeting where the construction was approved. At this time the Board had tendered costs for project management, survey, clearing and line construction, approved funding from YG and YDC and a YUB-approved PPA with Minto mine. At this time it was determined that there was acceptable risk given future net revenue benefits.

Board hadn't liked the project, we would be asking ratepayers to eat another million dollars. And that was not the decision we made then" (Transcript, page 182).

- As explained during the Resource Plan hearing, the preliminary cost estimates were based on appropriate reviews and assessments undertaken by senior members of staff in conjunction with outside experts. "information was developed through visits with engineering firms and others that could potentially be involved in the design of the development; estimates were based on engineering expertise and consideration of pricing current jobs of similar size, length, wires, and substations" (see Transcript, pages 557-58).

- YEC in prior appearances before the Board (Resource Plan, PPA, Part 3) was very clear that the project cost numbers were preliminary (transcript page 557, lines 9-11); YEC did not proceed with the project until it had tendered numbers for most cost element (these were numbers taken to its board, reviewed and approved). The fact that the earlier cost estimates were not based on preliminary engineering was discussed at the Part 3 hearing in the context of this project's ability, due to its specific project benefits, to tolerate higher costs of 20% and considerably more above the mid-point cost estimates. It was noted at that time that the focus was on how much latitude there was for the project to continue without an adverse effect on ratepayers (Transcript, pages 179-180).

Substation Scope Changes

Project Scope changes are reviewed in response to YECL-YEC-1-9(b). At transcript page 183, counsel for YECL asserted that if the original substations had been built the costs for the project would have been higher; (transcript page 580-82 addresses energizing Pelly Crossing line at a lower voltage).

Mr. Morrison clarified at transcript page 496, lines 1-12 that, "one of the reasons that there is the scope changes is when we got our heads around what we really needed in terms of the operability of the system, and we had some of our -- some of the engineering people look at it and some of our engineering advisors look at it, there was a realization that they really didn't need the Carmacks substation that was previously proposed. And what we went to was a -- you know, from a design engineering point of view, was what was needed versus what somebody thought we had needed previously".

Page 496, lines 13-15, Mr. Morrison noted there were no compromises in terms of operating the system; Undertaking #26 further clarifies this point noting that the underlying rationale for the scope changes was due to determinations regarding what would be most appropriate for CSTP Stage 1 after preliminary engineering was complete. The following points were noted:

- YEC had initially planned to build (as part of CSTP Stage 1) a more complicated substation at Carmacks and a 138/25 kV substation at Pelly Crossing.
- After preliminary engineering the following key determinations were made with regard to the project (by September 2007 when YEC's Board approved proceeding with CSTP Stage 1):
  - A more complicated substation at Minto Landing was necessary and preferred for system stability and Carmacks was made into a simpler switching station.
  - Second, feeding Pelly Crossing during Stage 1 with the 138 kV line energized at 25 kV would provide cost savings by allowing the 138/25 kV substation at Pelly Crossing to be deferred until Stage 2 as required.

Board Counsel asked (transcript, page 586) whether it is fair to compare final costs to Part 3 hearing estimates given the scope changes related to the substations. Mr. Osler noted at lines 11-24 the points of similarity and difference between the preliminary estimates and the construction approval estimate. More detailed review was subsequently provided in Undertaking #26.

Yukon Energy submits that full consideration of the substation scope changes confirms the prudence of the decisions made by Yukon Energy and the necessity and prudence of the costs as incurred for CSTP Stage 1.

5.1.2 Minto Diesel Units

The Application recognized the need to justify a business case for purchase of the Minto diesel units. Yukon Energy submits that this business case has been confirmed as required, and that the forecast costs for these units as set out in the Application should now be approved by the Board.

Order 2007-5 provided that before the units would be approved as an additional rate base, Yukon Energy must demonstrate the need for the units and provide a business case supporting the option to purchase the units at the Mine site. This demonstration of need was to include:

- Evidence that these units were required (based on the capacity planning criteria adopted in the 20-Year Resource Plan) and how the capacity addition stacks with other projects identified in the Resource Plan.
- Justification for the purchase as the least cost option.

The business case for the Minto diesels addressing these requirements is provided at pages 5-7 through 5-11 of the Application and further discussion is provided in response to YUB-YEC-1-

12(b) and YUB-YEC-1-36(c), UCG-YEC-1-76(c), PWP/HML-YEC-1-22 and PWP/HML-YEC-1-23. The business case was also discussed at the hearing (transcript pages 196-203; pages 556-61).

The Units are Needed

The case for need in relation to YEC's capacity planning criteria was summarized in discussion on the transcript at page 557. It was noted that both the Minto diesels and the Whitehorse Mirrlees units are needed in the time periods discussed in the Application, and the acquisition of the Minto units does not alter or replace the requirement for the completion of the Whitehorse Mirrlees rebuild or the Faro Mirrlees Refurbishment. The acquisition of the Minto diesels has only affected the timing related to when the refurbishment of the final Whitehorse unit (WH1) would be required.

The additional value provided by the Minto units and the requirement for these units in addition to the Whitehorse and Faro Mirrlees units was discussed in light of the capacity planning criteria and the need to be mindful of current capacity constraints and their impact on undertaking ongoing refurbishment work going forward. At pages 558-61 of the transcript, Mr. Bowman provided an assessment regarding how the Minto diesels fit within the capacity planning criteria reviewed during the 2006 Resource Plan hearing. It was noted that the peak forecast in the application for 2009 provided for a surplus of 3 MW (based on the forecast at the time with Faro Mirrlees and WD3 underway and without Minto Diesels). Mr. Bowman indicated that this was a concern for the following reasons:

> That is a problem, first, because the peak this last winter was about 2 megawatts higher than had been forecast; second, because if you only have a surplus of 3 megawatts, you don't have an easy ability to take out of service a 5 megawatt unit and do the work that's needed on it. Because when you take it out of service, you are driving yourself into a deficit, or you bound yourself into having to do it over the course of the summer, when the capacity is not required, with no ability to have it take longer or run into any trouble.

At pages 559-60[69] of the transcript, Mr. Bowman notes that the acquisition of the Minto diesels has provided a necessary cushion and flexibility related to timing with regard to completing capacity driven near term projects and provide for flexibility with regard to the timing:

[69] This is also discussed at page 556 line 16 to 25 and page 557 line 1: "the reason for refurbishing the Mirrlees and looking at the Minto diesel is to provide capacity, as we talked about. So they are there to provide the backup and the capacity on the system. So depending on the timing, whether or not we need to do Mirrlees in addition to Minto, whether we need to do Mirrlees two years from now and three years from now, is also going to depend on the load. But we would do them if we needed additional capacity, that's for certain."

> Once the Faro Mirrlees is done and the Whitehorse Mirrlees is done and we head into 2010, and the loads grow at the level that we are expecting, the second of the Whitehorse Mirrlees can be taken off-line and be refurbished in 2010 and brought online, and there wouldn't be big risk about making sure that you absolutely have to have it done for the start of winter.
>
> As we noted, that once that unit was brought back on, you would now have a small bit of cushion on the system, and the question is how quickly that cushion gets used up. And it could get used up by increases in peak load, which we continue to be surprised by, the extent to which Whitehorse's peak load is increasing, or it could be used up by addition of other loads, or by a loss of a unit, catastrophic failure, the type of things that can happen and that this whole criteria is designed to address.
>
> And it gives you the flexibility to then decide, do we want to incur the costs on WD-1 at a half a million a megawatt to get it back in service, or can we defer those costs, having spent a half a million a megawatt on the Minto diesels, and save the exact same amount of money. You are no further behind. So that's what the Minto diesels do. They are needed, and they are no more expensive, and they give flexibility in respect of the criteria, the N minus 1 criteria.

Cost is Competitive

The case for the Minto diesels as a competitive cost option was addressed in the Application at page 5-8 to 5-10, in response to interrogatories (UCG-YEC-1-76(c) and YUB-YEC-1-34(e)) and in discussion on the transcript at pages 198-99. It was noted that the benchmark for lowest cost capacity was established during the Resource Plan hearing process where the Mirrlees Rebuilds were defined as the lowest cost capacity option owing to the projected $0.482 million cost per MW determined at that time. As noted in the Application at pages 5-9, the current projected cost for the Minto diesels approximates $0.498 million/MW – a range competitive with the Whitehorse Mirrlees as the established benchmark for the lowest cost capacity alternative.

As noted in discussion at page 189-90, and at page 5-11 of the Application, other benefits that follow from the purchase of the Minto diesels include:

- The units are near a major load, and in that sense, two of the three units, as noted in other testimony, would rank next to the top in the diesel generation stacking order, so that having these units close to a load when YEC needs to operate the units is of benefit to the operation of the system. It was noted on page 192 that, "from the operability of the system, it's very, very helpful and very functional for us to have a generating source out towards the end of that long string, that long line, so that we can manage the balance in the system itself".

- The units can be run without any emissions impact in Whitehorse.
- Over the near term the units provide cost-effective contingency protection in the event that other mines develop in the area (that do not have surplus on-site diesel).
- After two years there is some flexibility in how two of the units may be used.

5.1.3 Whitehorse Mirrlees Diesel Generation Rebuilds

As reviewed in the Application, the Minto diesels, the Whitehorse Mirrlees Rebuilds and Faro Mirrlees Refurbishment are capacity additions that were pursued and are included in the Application in order to specifically meet basic winter peaking capacity requirements. These capacity additions are not proposed as generation projects to meet ongoing baseload generation needs.

As noted during the hearing, and in the Application and in IRs, the underlying basis or need for the Whitehorse Mirrlees units is driven by the requirement to have capacity available to meet N-1 capacity requirements, i.e., short term peaking diesel.

The Whitehorse Mirrlees projects have been previously extensively reviewed as part of the 20-Year Resource Plan and the Board provided its views in the Report to the Minister filed January 15, 2007. YEC has proceeded with these projects based on the outcomes of that proceeding. YECL-YEC-1-11(d) provides detailed references for supporting information from past proceedings where this project has been reviewed and recommended by the Board. The confirmation of Mirrlees technical feasibility was provided at the 2006 Resource Plan hearing in extensive detail. The business case today remains as provided in the Resource Plan proceeding. The Whitehorse Mirrlees life extension projects remain the most cost effective way to secure up to 14 MW of capacity in a flexible and staged manner, well below the cost of purchasing and installing new diesel generation.

Additional information regarding the Mirrlees Rebuild project is provided in the current proceeding in the Application at page 5-11, and in responses to interrogatories: YUB-YEC-1-36(e), YUB-YEC-1-34(f), YUB-YEC-1-37(b), YECL-YEC-1-50(e), LE-YEC-1-50, and UCG-YEC-1-76.

YUB-YEC-1-36(e) notes that the timing of the refurbishment of Diesel Unit #1 at Whitehorse (WD1) is not a cost benefit question per se, it is a question of when the required firm capacity is needed. If not required under the N-1 standby criteria, a later date for the refurbishment is preferable since the funds would not need to be expended until later. No cost estimate of mothballing the unit has been developed at this time. As set out at Tab 5, page 5-9, no decisions regarding rebuild versus mothball are expected to be made until closer to 2012, based on resources and load then expected to be on the system.

At page 195-96 of the transcript, the basis for using cost/MW to measure least cost/ most cost competitive options is discussed in relation to this project. Mr. Bowman notes that "from an economics type of analysis what the resource plan was working on was establishing, in the first instance, that there was a need for capacity", and once this was known the alternatives to get capacity and the costs of these alternatives were reviewed. During the initial resource plan filing, the Mirrlees option first related to 14 MW of generation at Whitehorse; this was later updated to include a further 5 MW related to the refurbishment of a Mirrlees unit at Faro totalling to a potential 19 MW at a total approximate cost of $5 million (with an additional cost of $1.4 million for work on common systems) and $2.3 million at Faro. The total $8.7 million cost over 19 MW provided the estimated $482 million per MW. Page 197 lines 9-12 note that this "was confirmed in the resource plan to be the cheapest option available to Yukon Energy, and it offered some benefits in terms of flexibility."

It was noted (transcript, page 197-98) that in looking at the current Application and the costs included in the filing at page 5-9:

> We -- when you're dealing with the numbers in this filing that you are dealing with, at page 5-9, what it's got now, that Mr. Osler would know, is a lot better numbers, after a lot more work, related to these units.
>
> In the resource plan hearing, the numbers I just went through, that led to 8.7 million, we did a further sensitivity that said, What if it came in $5 million higher than that? What if we really missed the mark? Because we knew that there was a lot of uncertainty, 35-year-old units taken apart, you are not quite sure what you will find inside. And it was still a project, even at that upper level.
>
> What we now know, based on what's here, and what's underway, units that have been taken apart and basically a few of them put back together, or close there to, is that we are on track for the lower cost estimate that we went through the resource plan, approximately half a million a megawatt, still holding at approximately that level, for the Mirrlees that are being done. And that includes costs all the way out to 2012, as they are all done in an orderly sequence.

At page 2-14 of the Application (and in discussion on the transcript at page 559-61) it was noted that the N-1 criteria is the driving capacity planning criteria factor on the WAF system and Yukon

Energy has incorporated this criteria into its planning activities in the test years with generation additions noted in Tab 5 (Minto Diesels and Mirrlees) required by the N-1 criteria.[70]

The information provided on the record to date notes YEC's success in securing the capacity required to meet winter peak capacity shortfalls on WAF (discussion at page 195-203):

- Discussion notes success in managing risks, with the outcome being the ability to complete the projects in a timely fashion while ensuring part supplies and assistance for completing the work is available.[71]
- Mr. Bowman notes at page 198 that the rebuilds and refurbishment of the Mirrlees units, which were considered the lowest cost option for achieving the required capacity as noted during the resource plan hearing, are well on track to being achieved at the lower cost estimate provided at that time.[72]

In summary, the evidence confirms the prudence and necessity of the Application's forecast costs for the test years for the Whitehorse Mirrlees refurbishment, and these costs should accordingly be approved by the Board.

5.1.4 Faro Mirrlees Diesel (FD1) Recommissioning

This project has been previously extensively reviewed as part of the 20-Year Resource Plan and the Board provided its views in the Report to the Minister filed January 15, 2007. YEC has proceeded with this project based on the outcomes of that proceeding. YECL-YEC-1-11(d) provides detailed references for supporting information from past proceedings where this project has been reviewed and recommended by the Board.

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[70] In discussion related to the need for both the Minto Diesels and the Mirrlees Rebuilds as part of Yukon Energy's capacity planning requirements, it was noted that by the end of 2009 there was a forecast surplus of only 3 MW without the Minto diesels. As noted at page 559, lines 10-11, the winter peak this past year was 2 MW higher than forecast.

[71] On the transcript at page 200-01, Mr. Morrison notes that risks noted during the Resource Plan process (i.e., ability to actually perform rebuilds and ability to access required spare parts) have been successfully addressed: "we've found that ....we can get the parts, and that probably the original equipment manufacturer is the best source of the parts, even though they -- you know, they don't have as big an operation in Canada as they used to have, we still seem to be able to get the parts and get them in a fairly timely manner". He also notes that YEC has secured assistance from BC Ferries' who have a degree of expertise with dealing with Mirrlees engines and have provided such assistances to YEC, "They also have a very, very large and comprehensive cadre of qualified Mirrlees mechanics and experts, because they fix these engines all year long."

[72] Page 198 lines 4-14, "What we now know, based on what's here, and what's underway, units that have been taken apart and basically a few of them put back together, or close there to, is that we are on track for the lower cost estimate that we went through the resource plan, approximately half a million a megawatt, still holding at approximately that level, for the Mirrlees that are being done. And that includes costs all the way out to 2012, as they are all done in an orderly sequence."

Faro Mirrlees are discussed at page 5-12 of the Application. YECL-YEC-1-11(d) Revised also provides references for materials filed during the Resource Plan hearing that provide the justification for proceeding with this project and its inclusion in rate base in the test years. Exhibit B-16 (filed during the Resource Plan hearing process) discusses at page 3-6 the Faro Mirrlees as "a suitable candidate for rehabilitation consistent with the Whitehorse Mirrlees". It was considered attractive for the following reasons:

- It adds new capacity (5 MW) to the system and aids in addressing the shortfalls that arise due to Yukon Energy's decision not to proceed with Marsh Lake Fall/Winter Storage.
- No existing units must be taken off-line to allow rehabilitation work to proceed (unlike WD3, which is required capacity on the system, cannot be taken off-line for rehabilitation work except in low load periods such as summer). This Faro Mirrlees unit has now been partially disassembled similar to WD3, and no major issues have been identified.

Additional information on the Faro Mirrlees was provided in the following interrogatory responses filed during the current proceeding.

- UCG-YEC-1-79; notes the project has not been designated pursuant to Part 3 of the PUA and further regulatory reviews are not anticipated.
- YUB-YEC-1-36(d): notes the original budget for this project in total, as set out in the November update to the Resource Plan, and reviewed in section 6.9 of the Board's Recommendations on the Resource Plan, was $2.3 million. The forecast 2008 spending in the GRA was $1.158 million to complete the project. While the project was not completed by year-end 2008, the total spending required to complete the project is still forecast at approximately this same level, and remains below the $2.3 million level forecast in the Resource Plan.

5.1.5 Aishihik 3rd Turbine

The Aishihik 3rd Turbine project was discussed at page 5-12 and 5-13 of the Application. The project has been extensively reviewed by this Board through various separate review processes over the years: the 1992 Resource Plan hearing, the 2006 Resource Plan hearing; the 2007 CSTP Part 3 hearing. The installation of the third turbine at Aishihik has also separately been reviewed by the Water Board during the Aishihik re-licencing process. The YUB has consistently recommended YEC proceed with this project (subject to timing considerations that the Board deemed to have been met in its Part 3 recommendations).

This project was further discussed in the following interrogatory responses

- UCG-YEC-1-17(a) sets out the economic rationale for the project as described in Appendix C of the Resource Plan proceeding, and further described in the PPA Application and in Yukon Energy's 2007 Part 3 Application concerning the Carmacks Stewart Transmission Project.
- YUB-YEC-1-36(h): AH3 is still an economically viable option given the current costs of fuel; it is noted that the economics of an Aishihik 3rd turbine was previously reviewed in the Resource Plan hearing, using diesel at $0.70 to $0.75 per litre and the project was determined to be economic even absent government funding. Current and projected fuel prices imply an increase, rather than a decrease, in these net benefits.

Yukon Energy submits that the justification for proceeding with the Aishihik 3rd Turbine projects has been confirmed. Its costs will not come into rate base during the test years.

5.2 PROJECTS $100,000 TO $1 MILLION

Parties reviewed various specific issues in IRs as regards capital works projects costing from $100,000 to $1 million, and Yukon Energy provided additional information on these projects. None of these projects were subjected to challenge during the hearing, and Yukon Energy submits that the costs as forecast in the Application for these projects should be approved by the Board.

5.3 DEFERRED COSTS

Parties have focused IRs and cross examination regarding forecast deferred costs primarily on matters relating to feasibility study and other costs for potential new renewable generation or transmission projects. Regulatory costs relating to rate case matters are addressed elsewhere in this argument.

5.3.1 Overview of Basis for Major Project Study Cost

As reviewed in section 1.2 of this argument, continuing load growth is materially reducing the surplus hydro available on the system and, and as part of the "orderly process" commenced in 2005 Yukon Energy has been engaged in a planning process to expand the available complement of renewable generation and transmission interconnections to address emerging baseload diesel generation requirements. Both cost and environmental reasons provide strong incentives for Yukon Energy to expand the available complement of renewable generation, as well as transmission interconnections that support enhanced use of renewable generation in Yukon to displace forecast baseload diesel generation.

Relevant major deferred costs are included in work-in progress for planning engineering, permitting and potential tendering activities, as required, for the Mayo B hydro generation enhancement, other generation feasibility assessments, Western Copper connection and CSTP Stage Two (as discussed at pages 5-19 to 5-21 of Application).

YECL noted in cross examination the sharp increase in planning and study costs in the test years, inquiring as to the business case underlying spending on planning and feasibility for projects such as Mayo B, and indicating concern regarding ratepayers being "stuck with the costs" should the projects not ultimately proceed.

While forecast spending on planning and studies related to new renewable sources of generation has increased considerably in the test years Yukon Energy has in its evidence, interrogatories and cross-examination response justified this increase in spending as necessary and reasonable and subject to ongoing review and consideration as projects in feasibility planning are further defined:

- Transcript, page 144, lines 12-23, "the amount of money that we are referring to, the 15, 16 million, ultimately is that's very large amounts for Mayo B, and it's going to go through some of key decisions before that type of money is spent. It's got some other planning costs for other projects that will go through key decisions before it's spent. We will answer any questions we can to help demonstrate why these studies are prudent and reasonable best ways to get to the next step of each of the projects"
- At page 138, lines 8-12, "the monies are being spent because people want to get on and do the project because it makes sense given the loads that are expected to arise".
- At page 134, "these monies are put into the application but they are -- it's been stated over and over again in the application and IRs they are subject to ongoing review, and they will not be spent if the circumstances arise that the project looks like it's not going to move forward."
- Also at page 134-35 it is noted, "In order to spend this type of money on these projects, they would have to and keep going through a lot of tests, the board of directors and the management of the company that would give them confidence to believe these projects are going to happen and that they are -- you know, these monies are prudently and wisely spent".

The amounts included in deferred costs for Mayo B and CSTP Stage 2 and other potential major future renewable generation projects or transmission connections do not affect revenue requirements in the test years or the rates as currently proposed. Deferred costs for these major projects are essentially planning provisions made at the time the Application was filed, and are subject to review and update as matters progress, and are not expected to be fully spent unless the project continues to move forward through each review stage by the YEC Board. These numbers have been subject to update during the hearing process already with YUB-YEC-1-38(b) ultimately reducing some deferred cost numbers based on more current information.

5.3.2 Mayo B

Mayo B (as noted page 5-20 of the Application) has been identified as a potential priority near term hydro generation expansion opportunity that could displace up to 38 GWh/year of baseload diesel generation. Information regarding the Mayo B expansion project is provided in the Application (at page 5-20); the business case for pursuing the project at this time is elaborated on in YECL-YEC-1-5 Revised, and in YUB-YEC-1-38(a). UCG-YEC-1-89 also provides a review related to how this project was identified as part of (and fits into) the overall 20-Year Resource Plan reviewed in 2006. Undertaking #28 provides the near term load requirement context for considering the Mayo B project at this time.

Project Costs and Funding Requirements

With regard to the requirement for government funding in order to make the project economic, the following points were made on the transcript at pages 210-12:

- Mayo B (with estimated costs at $120 million) would not on its own be considered economic and some government funding is required. It was noted that $50 to $60 million in funding is expected to lower the levelized generation to the range of 8 to 10 cents a kilowatt hour (the green power generation in British Columbia for new green power) which would be a reasonable basis for pursuing the project.
- Mr. Morrison noted that the cost-benefit consideration underlying the pursuit of this project was the requirement, without 30 to 40 GWh of new generation from Mayo B, to run diesel units; the inability to displace the projected load growth and requirement for baseload diesel in the absence of Mayo B is a key consideration underlying the pursuit of the project:

> If we have to generate that 30 or 40 gigawatt hours of new load, additional growing load, with diesel, that's the easy way to do it, we just turn the diesels on. Really simple. We could turn the diesels in Dawson back on, and, you know, there is 3 or 4 or 5 megawatts there. We can use those. We've got diesels in Mayo and can use those. But I would put to you, and other people who are probably more expert than I in terms of quantifying numbers again, I would put it to you that the fuel cost of diesel, just the fuel cost of generating a kilowatt hour of diesel, is

> roughly 25 to 30 cents, even today. So just do the math. It's really simple: 30 cents times 30 gigawatt hours, that's $10 million a year in diesel costs. Ratepayers can't afford that. We don't want to do it for greenhouse gas emissions purposes, for compliance with all kinds of regulations.

Feasibility and Planning Costs

It was noted in discussion on the transcript at pages 132-33, that while the Application includes $8.2 million in forecast spending on feasibility work over the test years, these costs are subject to ongoing regular review in order to prudently manage risks.[73] Mr. Morrison noted at pages 215-16the manner in which YEC balances risk in relation to prudently incurring further costs in relation to Mayo B:

> We look at the project and look at a certain set of information. We had to do some baseline, we had to do a series of tasks we had to complete in order to file an environmental application. We have done that with YESAB. We filed the application. We are not going very much further down this road in terms of expenditure, and I mean very much at all, without getting some clear indication as to whether or not we are going to get funding and, therefore, this project is going to go ahead. So part of the assumption in the spending of the 8.2 or $8.8 million is that we will solve some of those questions, and so we would continue to spend some money. But there's a whole bunch of other decisions yet to be made prior to us spending the money for sure this year, just to be clear.

These amounts included in work in progress do not affect the revenue requirements or the rates in the test years, and reflect planning provisions that existed at the time the Application was filed.

Options

With regard to options to Mayo B being considered it was emphasized that given projected load growth, requirements will quickly outstrip available surplus hydro. Yukon Energy has noted that it was not an assessment of whether Mayo B was the preferred option to other available options;

[73] At page 133, lines 3-21, "Mayo B is assuming that people are going ahead on the schedule of trying to get this project in service by the fall of 2011 and that in order to do that they are securing funds as required and doing all the things that are necessary to make a decision to keep moving on this project at the level that this assumes, which includes aggressive -- doing field work this year and drilling and also doing all the engineering in order to be able to start construction next spring. Unless things keep happening that would give the company confidence that it's prudent to spend those monies, those monies -- that $6 and a half million will not be anywhere close to spending the numbers you're looking at here. And the same arguments would apply to the other projects."

Mayo B was the largest single project that could reasonably be licenced and built within the timelines required for in service in 2011 in order to meet load requirements. At page 210 it was noted,

> The real difficulty that we have here is that we have increasing loads. The only option that we have in front of us is to get the quantity of energy that we need. And when I mean that, in the 30- or 40-gigawatt-hour-a-year range is Mayo B. If we could find another project that was cheaper and we could do it in the time frame, we would be looking at it.

It was noted that other projects being currently being assessed (Atlin, Gladstone) are cost effective and simple to construct, but present challenges related to the ability to complete timely regulatory reviews (pages 142-43). Mayo B is the only option that can be reasonably relied upon to potentially provide for new generation required within the 2011 time periods described. Further, and as noted on the transcript at pages (516-18)[74] Mayo B is required in addition to other options such as Gladstone and Atlin in order to meet system requirements using renewable generation instead of diesel; as noted by Mr. Morrison (page 518, lines 4-18):

> We don't need Mayo or Atlin, Gladstone, Marsh. We need Mayo and all of those just to meet a very -- what I would say to you is a very conservative load forecast going forward for the next five five -- four or five years.

5.3.3 CSTP Stage Two – Grid Connection Design and Contracting

As noted at page 5-21 of the Application, final engineering design, costing and tendering activity is anticipated to be required during 2009 to protect potential in-service for CSTP Stage 2 as may be required (in response to new mine loads) in 2010 or 2011. Budget and timing is subject to ongoing reviews.

YECL-YEC-1-11(d) provides references to detailed information related to the CSTP Stage 2 that has been reviewed in previous proceedings (Resource Plan, PPA hearing and Part 3 Review). YECL-YEC-1-8(d) provides an assessment of projects risks, risks of not proceeding, alternatives to the project and benefits to ratepayers from proceeding with the projects.

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[74] Mr. Osler notes, "Yukon Energy's assessment as of mid '07 was that they needed to go out and get a priority of what they could get in terms of energy from renewable resources in the period 2010, 15 in, say, 25 to 50 million kilowatt hours range. And as we went through the next year after that, we realized that probably we should be asking the question more like 50 to 100 million kilowatt hours. So the board of directors when we look at these matters is saying, we need all of these projects. We need the Gladstone, we need the Atlin, and we need the Mayo. And it's not that we're giving one more priority than the other. It's just that, you know, the Mayo project can be acted on in a decisive manner by doing some work and then filing an application with, yes, I've been trying to get some government funds".

PWP/HML-YEC-1-27 provides relevant considerations related to the ongoing planning activities related to the CSTP Stage 2, noting:

- The ability to reduce potential diesel usage due to the potential future connection of Alexco to the grid.
- The ability to be ready to advance and proceed with the project in the near term is critical to the extent government infrastructure funds become available.[75]

Continuing load growth will materially reduce the surplus hydro available on the system. Without CSTP Stage 2, the limited near term renewable resource development opportunities to displace forecast diesel generation would be further constrained. The interconnection enables each new renewable generation project to help meet new load on both grids. Connecting the MD and WAF grids is a key element supporting new hydro or other renewable green development (including larger projects such as Mayo B on the Mayo Dawson grid).

YECL-YEC-1-8 Revised elaborates on the business case for CSTP Stage 2, providing updated information on projected costs, risks, government funding requirements, options and ratepayer benefits. These matters were reviewed in cross examination by YECL's counsel at transcript pages 217-223.

5.3.4 Other Generation Feasibility

Undertaking #28 and CW-YEC-1-31 provide a review of industrial loads on the system and the underlying factors which have led YEC to undertake feasibility work on projects (including small scale projects such as Gladstone, Atlin, Marsh Lake and larger scale projects such as geothermal and Houle) in order to enhance the compliment of renewable generation projects in Yukon in light of dwindling surplus hydro. As noted in CW-YEC-1-31, "developing either enhancements to existing hydro projects, or new renewable generation, is very costly and requires long planning times" but projected load increases, cost and environmental considerations all provide strong incentives to pursue renewable generation projects in order to address long term bulk power needs.

All of the renewable generation and transmission projects currently being pursued are necessary activities for Yukon Energy at a generation/transmission level to undertake in order to manage and plan for its system. Mr Bowman noted that ultimately, "That would be the basic premise to

[75] As reviewed in YECL-YEC-1-8 Revised, government and/or mine funding of at least $35 million of the estimated $40 million project capital cost is viewed as a pre-requisite to YEC being able to proceed at this time with CSTP Stage 2. To the extent government infrastructure funds become available, the ability to be ready to advance and proceed with the project in the near term is critical.

why the studies were done, why they were approved by YEC and undertaken internally and why they were included in ratebase". (At page 139, lines 9-18)

At page 136 YECL's counsel inquired whether there were any benefits to ratepayers if projects included in planning and study costs did not proceed (with their costs being amortized and included in rates). Mr. Bowman noted that even if the studies are completed and the projects do not ultimately proceed at this time, there are enduring benefits that issue from undertaking and performing the work. This includes the following:

- Having projects "shelf-ready" such that they are ready to proceed at some future date as circumstances change.[76] For example, CSTP Stage 2 has already proceeded through its YESAB review such required government funding or other contributions become available, the project can proceed expeditiously. Mr Osler noted at page 138-39, that deferred costs related to Mayo B in the test years were largely related to completing the YESAB filing for the Mayo B project and "It was always understood that that filing was a goal by itself that the board of directors had approved and that the benefit of that would be we get the project regulated and get it approved so that next time in the worst case you have the environmental approvals in place rather than having to start at Square 1, because timing is everything So in that specific case, there was a very specific product, milestone that's there."

  Mr Bowman also noted that Yukon Energy has been able to pursue studies related to the current suite of renewable generation projects in a timely fashion largely due to the fact that a great deal of feasibility work with respect to particular projects and sites was undertaken in the past. This work does not simply "go away" if the project does not proceed at present, "Even at the time we filed the 2005 resource plan we had quite a list of assets in the colloquial sense from the work that people have done in past studies on sites. So the studies don't go away in terms of their value. That would be one point."
- The feasibility work being undertaken also results in products that have other uses and applications of ongoing value to the utility, "I make some comment in the interrogatories about things like developing an overall system generation planning model that's being used for a number of purposes".

[76] See transcript page 514-15, "The other important part about Mayo B is it's the only hydro project that we have in the development stage that can be built within the time frames that we have where we're going to -- where we anticipate or forecast we're going to need the power. So we have a lot of other hydro studies, but none of them advanced to the stage and none of the projects advanced to the stage where they're ready in a two- or three-year period to bring online. And that just really, really emphasizes the point I was trying to make earlier about the need to do research, the need to do planning and system studies on an ongoing basis, because we have to get some projects up to the point where they're shelf ready, and we can then take them off the shelf when we encounter these increases in load".

- Projects such as Mayo B also involve activities that include work with the community; "there's always benefits to being able to engage with the local community and work with them through the issues related to the future with respect to plans".

The YECL counsel asked whether Yukon Energy had undertaken a written cost benefit analysis of the feasibility and planning work being currently undertaken. In response on page 143 it was noted that, "Yukon Energy went through a process to rationally focus on the studies of these particular projects that are being studied". It was noted that subsequent to the Resource Plan hearing, Yukon Energy dispatched a team to assess a short list of possible projects to meet load requirements over the near term (to 2015), and to provide a list of the projects that could be advanced to provide 25 to 50 gigawatt hours of diesel within required timelines. At this point cost benefit analysis is focused primary on diesel displacement. The team considered practical options, the technically available options, cost and the ability to obtain required licences within the timelines being considered and a short list was indentified of Mayo B, Gladstone, Atlin, Marsh and the early days at looking at geothermal.

At page 141-42 of the transcript, it was noted that at the feasibility and planning stages the cost benefit analysis is focused on a broad assessment of need, options and developing the suite of preferred options available to meet that identified need. As studies progress and information becomes more refined, the analysis will similarly become more refined and identifiable as a cost benefit study of a particular project, "by the time it gets to a final decision of the board of directors, it's very definitely a full assessment of the risks, costs, and benefits".

Undertaking #28 was provided in response to Board counsel seeking additional information, in part, on the specific short-listed renewable generation projects under active consideration. The response provides a project-specific summary of current estimated costs, timelines and potential generation benefits.

Yukon Energy submits that the evidence confirms the prudence of the resource planning and study process being carried out with regard to new potential near-term renewable generation projects.

5.3.5 Western Copper – Grid Connection YESAA & PPA

The Application notes at page 5-21 funds budgeted for 2009 for necessary planning, engineering permitting/YESAA review and negotiation of a power purchase agreement related to a grid connection for Stage One CSTP of the planned mining project at the Carmacks Copper mine site. The forecast loads and anticipated grid connection are discussion on the transcript at pages 106-10. It was emphasized both in the Application and on the transcript (page 109, lines 14-24) that, if incurred, the costs of the spur line would be 100% recovered from the mine.

5.3.6 Projects between $100,000 and $1 Million

Parties reviewed specific issues in IRs as regards deferred cost projects costing from $100,000 to $1 million, and Yukon Energy provided additional information on these projects. None of these projects were subjected to challenge during the hearing, and Yukon Energy submits that the costs as forecast in the Application for these projects should be approved by the Board.

6.0 BOARD DIRECTIVES AND RECOMMENDATIONS

The Issues List approved in Board Order 2009-1 provided for review of Board Recommendations and Directives. A limited number of issues have arisen during the hearing process on these matters, including IRs from the Board.

Since 2005 a series of hearings have led to Board Directives to Yukon Energy specifically (as well as directives to YEC and YECL jointly) and Recommendations (primarily to the Yukon Government):

- Tab 6 of the Application specifically reviewed directives contained in Board Decisions since the submission of the 2005 Required Revenues and Related Matters application, and (where relevant) Yukon Energy's response. Relevant Board directives discussed therein include those issuing from Order 2005-12 (Revenue Requirement and Related Matters), 2007-5 (PPA hearing) and directives on regulatory costs incurred during the Resource Plan series of reviews (Orders 2007-7, 2007-8,2007-9 and 2008-1). Page 6-1 of the Application also notes Order 1996-7 which directed YEC and YECL to design a rate rebalancing program to target all customer class revenue/cost ratios of 90% to 110% over a 10 year period, and notes actions taken since this time.
- Order 2009-2 issuing form the YECL 2008-2009 provides some joint direction to both YEC and YECL related to consultation with regard to and development of DSM and IPP policies. While the Order relates to a separate YECL process, YEC is cognizant of the Board's stated views and desire to see both utilities undertake joint action related to these issues. (This is similar to joint direction to both YEC and YECL provided in Order 2007-5 related to the Board's desire for a Cost of Service study to be provided; the direction arose in a Yukon Energy process, but the direction was provided jointly to both utilities.)
- Recommendations to the Minister of Justice were provided in Reports to the Minister issuing from two requested review processes undertaken pursuant to separate provisions of the Public Utilities Act:
    - An Application by Yukon Energy Corporation for review of its 20-Year Resource Plan: 2006-2025, which the Minister directed the Board to carry out and report on with recommendations.

- o Yukon Energy Corporation Application For An Energy Project Certificate And An Energy Operation Certificate Regarding The Proposed Carmacks-Stewart Transmission Project, with regard to which the Minister directed the Board to review and provide recommendations pursuant to terms of reference provided by the Minister.

6.1 BOARD DIRECTIVES

Tab 6 of Yukon Energy's Application is focused specifically on directives issuing from prior Board Orders. The Board also asked several interrogatories related to the status of various directives:

- YUB-YEC-1-12 – Directions related to business case for Minto Diesels (Order 2007-5)
- YUB-YEC-1-19(a) – Direction related to Rate Schedule 35 (Order 2007-5)
- YUB-YEC-1-19(b) and (c) Concerns regarding the lack of a cost of service (COS) associated with this new rate proposed Rate Schedule 35 and 39, and Order 2007-5 Direction that YEC and YECL to provide electronic COS models for the next GRA.
- YUB-YEC-1-20 Order 2007-5 Direction that YEC and YECL must provide a complete COS study and rate design with their next GRA.
- YUB-YEC-1-23(d) - Order 1996-7 and direction with respect to a rate-rebalancing program.

The Yukon Energy responses on a joint YEC/YECL Phase II filing as provided to the above IRs reflected the approach adopted initially in the Application, based on Yukon Energy's then understanding of current priorities in light of OIC 2008/149 and OIC 2007/94 and other considerations. Subsequently, based on review of Order 2009-1 and Exhibit A-10, Yukon Energy has informed the Board that it plans to meet with YECL after the current hearing to plan for a joint Phase II application covering cost of service, rate design, ESRs and other matters as set out In Exhibit B-13 and Exhibit B-12.

6.2 JOINT DIRECTIVES

In Order 2009-2 (issuing from the YECL 2008/2009 GRA) the Board provided its views and expectations of both utilities related to the development of policies related to DSM and IPPs.

In respect of DSM, the Board has set out its expectations in Appendix A of Order 2009-2 which notes as follows at page 44:

> The Board views DSM as another critical issue for Yukon. The Board directs YECL in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to DSM initiatives and include this policy paper as part of YECL's and YEC's next

GRA. To be clear, YEC and YECL are to jointly lead these processes and jointly submit the policy papers (IPP and DSM) in their next GRA. The DSM policy papers are to provide DSM initiatives developed through negotiations with Intervenors and communities in its service territory and YEC's service territory.

YEC has noted in response to UCG-YEC-1-20, YUB-YEC-1-27 and on the transcript at pages 569-572 the following with regard to this board direction:

- Yukon Energy has reviewed the Board's decision on this matter, as well as its earlier related recommendations in the Resource Plan report, but has not yet had an opportunity to meet with YECL in this regard.
- Yukon Energy has not in its current GRA contemplated or budgeted for these activities.
- Yukon Energy has not had any role yet in the Yukon Government review of these policy matters; however, Yukon Energy is open to receive proposals from IPPs
- Yukon Energy requested further direction from the Board related to the scale of activities anticipated to be undertaken and confirmation of some form of deferral account for expenditures, presumably targeted for disposition at the next GRA.

6.3 BOARD RECOMMENDATIONS

Recommendations by the Board to the Minister do not arise from typical rate review processes, but generally arise from special processes as requested by the Minister pursuant to the PUA (including now Part 3 of the PUA).

As was noted in discussion at the hearing, the PUA provides that the Minister may refer a matter to the YUB for review; the Board then must review the matter and provide the Minister with recommendations related to the matter. Recommendations provided by the Board through these processes are very different from Board directives, i.e., the recommendations are to be made to the Minister (and not to Yukon Energy or YECL) and issue from processes undertaken outside of the Board's normal jurisdiction where specific directives may be provided to subject parties.

Some confusion persisted during the oral hearing with regard to the premise underlying these separate review proceedings and their outcomes, with counsel for YECL inferring that at the Resource Plan hearing Yukon Energy was seeking Board "approval" of the Resource Plan. It was clarified that Board "approval" for the Resource Plan and for individual projects reviewed under Part 3 of the Public Utilities Act was not sought and could not effectively be provided given the limitations provided by the PUA. Yukon Energy did not seek "approval" of the Resource Plan (or the CSTP during the Part 3 process); a review of the Resource Plan and the CSTP was sought through Ministerial direction and Recommendations (not directives or approvals) were provided by the Board to the Minister.

As noted at pages 76-78 of the transcript, Yukon Energy did not commit to seek YUB "approval" of projects greater than $3 million, but instead committed to seek Board review of these projects (this was accomplished through the Resource Plan Review process.) Mr. Osler noted at page 76 line 25 and page 77, line 1-11:

> The problem in Yukon is there is no statutory provision for the Board to approve capital projects of utilities. But in the past, we have found ways to deal with that, and the resource plan was a good example in terms of the ministerial direction and the resource plan document, the Board giving recommendation. And we thought that that process had honoured Yukon Energy's commitment that Mr. Morrison had made in 2005 for the four or five key projects that were listed in the resource plan for the near term.

Further at page 79, lines 2-5 and lines 7-9:

> Mr. Keough, Yukon Energy did not seek the Board's approval and it did not get the Board's approval. The Board does not have the basis for giving same.

And

> The Board did recommend various projects, and Yukon Energy has been moving forward with those recommendations.

Yukon Energy's opening statement (Exhibit B-12) reviewed Mr. Morrison's commitment in the 2005 proceeding to work with the Board to find a mechanism to ensure that in the future YEC is before the Board on a regular basis, in an open and transparent manner. Yukon Energy has actively sought the Board's review of major capital projects, and has bee before the Board several times since 2005.

As intended, recommendations issuing from Board review process such as the Resource Plan hearing and the CSTP Part 3 hearing have provided Yukon Energy with the valued guidance that it sought related to the Board's views of proposed activities to be undertaken (including with regard to the Resource Plan views on capacity planning criteria, specific projects and approaches to addressing bulk system planning issues over the 20-year period reviewed).

With regard to the Resource Plan, since the recommendations were provided to the Minister in January 15, 2007, Yukon Energy has been able to proceed with necessary activities (as set out in the Resource Plan) with the comfort that the Board has reviewed these matters and provided its specific views on how they should be approached[77]. With regard to most matters YEC has proceeded in a manner that reflects the Board's recommendations and views. The importance of this review process to YEC's ability to move forward with required bulk system planning activities was set out in the Opening Statement (page 31, lines 8-25)

> Between 2005 and 2008 many steps have been taken to move forward in an orderly manner to deal with the priority regulatory issues, including Board review of Yukon Energy's 20-year resource plan in 2006, resulting in the Board's January 2007 report and recommendations to the Yukon government, which included many key recommendations on various matters, including new capacity planning criteria and confirmation that new near-term capacity was required. There were also specific recommendations regarding several near-term major projects which were proposed by Yukon Energy to enhance transmission and generation capacity on the hydro grid. Each of these projects have been undertaken, and the costs of the projects are included in the 2008-2009 GRA.

At page 75-76:

> The focus was essentially on generation and transmission planning in Yukon over the next 20 year, 2006 to 2025. And it focused on capacity planning criteria, as noted as a topic, and the implications of that for near term and longer term. And it focused on approaches to deal with the near-term to 2012, and for the four or five key projects listed there as major projects, which Yukon Energy wanted the Board to have the opportunity to review, and in Mr. Morrison's earlier commitment to bring before the Board projects costing $3 million or more, if possible, and also tried to deal with ways to approach longer-term planning beyond 2012, in light of all the various particular industrial scenarios that might emerge in load scenarios.
>
> And it all responded to an order setting the hearing in the Minister's letter that, I think succinctly said, asked the Board to review it from the point of view of the near term, as we have just discussed it, and the longer term, as we have just discussed it.

During the hearing, Yukon Energy also responded at pages 561 to 566 to questions from Board counsel regarding reconsideration of YEC's commitment as to the $3 million threshold for seeking Board review of projects (in light of the Board's recommendation in its Resource Plan report for a lower threshold of $1 million). Yukon Energy stated that it had not to date reconsidered this threshold, and reviewed some of the considerations that might affect this specific matter – including the need to rely on the government to provide the necessary framework for YEC to appear before the Board. In general, on policy as distinct from specific project matters, Yukon

[77] Matters reviewed during the Resource Plan hearing process are described at page 75-76 of the transcript.

Energy consideration of Board recommendations may involve parties other than only Yukon Energy.

Similarly, in response to questions during the hearing from various parties on future cooperation and joint submissions by YEC and YECL, Yukon Energy described its proposed approach and cautioned that it could not undertake on its own what outcomes may arise. (For example, in response to counsel for CW, transcript at pages 252-253 on coming up with a common forecast, it was noted that there are two utilities and they may well have differences of opinion, i.e., YEC would see such an outcome as desirable, but would have to see if that objective can be achieved.)